This document comprises a prospectus (the **"Prospectus"**) relating to Gran Tierra Energy Inc. (the **"Company"** or **"Gran Tierra"**) prepared in accordance with the Prospectus Rules of the Financial Conduct Authority (the **"FCA"**) (the **"Prospectus Rules"**) made under section 73A of the Financial Services and Markets Act 2000, as amended (**"FSMA"**), and approved by the FCA under section 87A of FSMA. This Prospectus will be made available to the public in accordance with Rule 3.2 of the Prospectus Rules.

The Company and the directors of the Company whose names appear on page 35 of this Prospectus (the **"Directors"**) accept responsibility for the information contained in this Prospectus. To the best of the knowledge of the Company and the Directors (who have taken all reasonable care to ensure that such is the case), such information is in accordance with the facts and does not omit anything likely to affect the import of such information.

Applications have been made (a) to the FCA for all of the shares of the Company's common stock, par value of $0.001 per share, (the **"Common Stock"**) to be admitted to listing on the standard listing segment of the Official List of the FCA (the **"Official List"**) and (b) to the London Stock Exchange plc (the **"London Stock Exchange"**) for all of the shares of Common Stock to be admitted to trading on the London Stock Exchange's main market for listed securities (together, **"Admission"**). It is expected that Admission will become effective and that dealings will commence in the Common Stock on the London Stock Exchange at 8.00 a.m. on 10 October 2018. The Company's shares of Common Stock are currently admitted to trading on the New York Stock Exchange American (the **"NYSE American"**) and on the Toronto Stock Exchange (the **"TSX"**) and, following Admission, will continue to be listed on the NYSE American and on the TSX. No application has been, or is currently intended to be, made for the shares of Common Stock to be admitted to listing or trading on any other stock exchange.

This Prospectus is issued solely in connection with Admission. This Prospectus does not constitute or form part of an offer or invitation to sell or issue, or any solicitation of an offer to purchase or subscribe for, any securities by any person. No offer of shares of Common Stock is being made in any jurisdiction.

Prospective investors should read the entirety of this Prospectus and, in particular, the section titled "Risk Factors" for a discussion of certain factors that should be considered in connection with an investment in the Common Stock. Prospective investors should be aware that an investment in the Company involves a degree of risk and that, if certain of the risks described in this Prospectus occur, investors may find their investment materially adversely affected. Accordingly, an investment in the Common Stock is only suitable for investors who are particularly knowledgeable in investment matters and who are able to bear the loss of the whole or part of their investment.

Gran Tierra Energy Inc.

(*Incorporated and registered in the State of Delaware, U.S. with registered number 6198266*)

Admission of 391,316,489 shares of Common Stock to listing on the standard listing segment of the Official List and to trading on the London Stock Exchange's main market for listed securities

Financial Adviser

RBC Capital Markets

RBC Europe Limited, trading as RBC Capital Markets, (**"RBC Capital Markets"**) is authorised by the Prudential Regulation Authority (the **"PRA"**) and regulated in the United Kingdom by the FCA and the PRA. RBC Capital Markets is acting exclusively for the Company and no one else in connection with Admission and will not regard any other person (whether or not a recipient of this Prospectus) as a client in relation to Admission and will not be responsible to anyone other than the Company for providing the protections afforded to its clients or for giving advice in relation to Admission or any transaction, matter or arrangement referred to in this Prospectus.

Apart from the responsibilities and liabilities, if any, which may be imposed by FSMA or the regulatory regime established thereunder, neither RBC Capital Markets nor any of its affiliates owes or accepts any duty, liability or responsibility whatsoever (whether direct or indirect, whether in contract, in tort, under statute or otherwise) or makes any representation or warranty, express or implied, to any person in respect of any acts or omissions of the Company in relation to Admission or for the contents of this Prospectus, including its accuracy, completeness or verification or for any other statement made or purported to be made by or on behalf of it, the Company or the Directors in connection with the Company, the Common Stock or other matters referred to in this Prospectus, and nothing in this Prospectus is or shall be relied upon as a promise or representation in this respect, whether as to the past or the future. RBC Capital Markets accordingly disclaims, to the fullest extent permitted by applicable law, all and any liability whatsoever, whether arising in tort, contract or otherwise (save as referred to above) which it might have in respect of any acts or omissions of the Company in relation to Admission and for this Prospectus or any such statement.

No person has been authorised to give any information or make any representations other than those contained in this Prospectus and, if given or made, such information or representations must not be relied upon as having been authorised by the Company, the Directors or RBC Capital Markets. Neither the publication or delivery of this Prospectus shall, under any circumstances, create any implication that there has been no change in the Company's affairs since the date of this Prospectus or that the information in this Prospectus is correct as at any time subsequent to its date.

The contents of this Prospectus should not be construed as legal, financial, business, investment or tax advice. Each prospective investor should consult his, her or its legal adviser, independent financial adviser or tax adviser for legal, financial, business, investment or tax advice. Prospective investors must inform themselves as to (a) the legal requirements within their own countries for the purchase, holding, transfer, redemption or other disposal of the Common Stock; (b) any foreign exchange restrictions applicable to the purchase, holding, transfer, redemption or other disposal of the Common Stock which they might encounter; and (c) the income and other tax consequences which may apply in their own countries as a result of the purchase, holding, transfer, redemption or other disposal of the Common Stock. The distribution of this Prospectus into certain jurisdictions may be restricted by law.

Information to Distributors

Solely for the purposes of the product governance requirements contained within: (a) EU Directive 2014/65/EU on markets in financial instruments, as amended (**"MiFID II"**); (b) Articles 9 and 10 of Commission Delegated Directive (EU) 2017/593 supplementing MiFID II; and (c) local implementing measures (together, the **"MiFID II Product Governance Requirements"**), and disclaiming all and any liability, whether arising in tort, contract or otherwise, which any "manufacturer" (for the purposes of the MiFID II Product Governance Requirements) may otherwise have with respect thereto, and the Common Stock have been subject to a product approval process, which has determined that the Common Stock are: (i) compatible with an end target market of retail investors and investors who meet the criteria of professional clients and eligible counterparties, each as defined in MiFID II; and (ii) eligible for distribution through all distribution channels as are permitted by MiFID II (the **"Target Market Assessment"**). Notwithstanding the Target Market Assessment, distributors should note that: the price of the Common Stock may decline and investors could lose all or part of their investment; the Common Stock offer no guaranteed income and no capital protection; and an investment in the Common Stock is compatible only with investors who do not need a guaranteed income or capital protection, who (either alone or in conjunction with an appropriate financial or other adviser) are capable of evaluating the merits and risks of such an investment and who have sufficient resources to be able to bear any losses that may result therefrom. The Target Market Assessment is without prejudice to the requirements of any contractual, legal or regulatory selling restrictions in relation to Admission. Furthermore, it is noted that, notwithstanding the Target Market Assessment, RBC Capital Markets will only procure investors who meet the criteria of professional clients and eligible counterparties.

For the avoidance of doubt, the Target Market Assessment does not constitute: (a) an assessment of suitability or appropriateness for the purposes of MiFID II; or (b) a recommendation to any investor or group of investors to invest in, or purchase, or take any other action whatsoever with respect to the Common Stock. Each distributor is responsible for undertaking its own Target Market Assessment in respect of the Common Stock and determining appropriate distribution channels.

The date of this Prospectus is 28 September 2018.

TABLE OF CONTENTS

Page

SUMMARY

Summaries are made up of disclosure requirements known as 'Elements'. These Elements are numbered in Sections A – E (A.1 – E.7) below. This summary contains all the Elements required to be included in a summary for this type of securities and issuer. Because some Elements are not required to be addressed, there may be gaps in the numbering sequence of the Elements. Even though an Element may be required to be inserted in the summary because of the type of securities and issuer, it is possible that no relevant information can be given regarding the Element. In this case a short description of the Element is included in the summary with the mention of 'not applicable'.

Section A – Introduction and Warnings		
A.1	**Introduction**	This summary should be read as an introduction to the Prospectus. Any decision to invest in the Common Stock should be based on consideration of the Prospectus as a whole by the investor. Where a claim relating to the information contained in the Prospectus is brought before a court, the plaintiff investor might, under the national legislation of the Member States of the European Economic Area (**"EEA"**), have to bear the costs of translating the Prospectus before the legal proceedings are initiated. Civil liability attaches only to those persons who have tabled the summary including any translation thereof, but only if this summary is misleading, inaccurate or inconsistent when read together with the other parts of the Prospectus or it does not provide, when read together with the other parts of the Prospectus, key information in order to aid investors when considering whether to invest in the Common Stock.
A.2	**Subsequent resale of securities or final placement of securities through financial intermediaries**	Not applicable. The Company is not engaging any financial intermediaries for any resale of securities or final placement of securities requiring a prospectus after publication of this Prospectus.

Section B – Issuer		
B.1	**Legal and commercial name**	Gran Tierra Energy Inc.
B.2	**Domicile/legal form/legislation/ country of incorporation**	The Company was incorporated on 6 June 2003 as a corporation under the laws of the State of Nevada, United States and was subsequently converted on 31 October 2016 into a corporation existing under the laws of the State of Delaware, United States. The Company currently operates under the General Corporation Law of the State of Delaware, as from time to time amended. The Company's registered number is 6198266.
B.3	**Description of, and key factors relating to, current operations/principal activities/principal markets**	Gran Tierra is an independent international exploration and production company with onshore oil production focussed in Colombia. The Group's core assets are located in the Middle Magdalena Valley and the Putumayo basins. The Group has interests in 30 blocks in Colombia and is the operator on 26 of these blocks. The Group's core producing assets include the Acordionero, Costayaco and Moqueta Fields in Colombia, which collectively represented 82% of the Group's production (WI) for the six months ended 30 June 2018. The Acordionero Field is located in the Middle Magdalena Valley Basin on the Midas block (100% WI, operated), which the Group acquired in 2016 as part of the acquisition of PetroLatina Energy

		Limited. The Acordionero Field provided production of 17,233 BOEPD (WI) for the six months ended 30 June 2018. The Acordionero Field provides near-term conventional development opportunities with significant waterflood potential. The Costayaco and Moqueta Fields are both located in the Putumayo basin on the Chaza block (100% WI, operated). The Costayaco and Moqueta Fields collectively produced 33% of the Group's production (WI) for the six months ended 30 June 2018 and have low decline rates. The Company believes the Group's existing portfolio in Colombia provides significant development inventory to continue to grow its production. The Group has successfully consolidated sufficient exploration opportunities to commence a three to five year continuous exploration programme, which it expects will be fully funded by cash flows from the Group's Colombian operations. The exploration programme targets drilling 30 to 35 exploration wells in primarily proven basins in Colombia, including the Putumayo, the Middle Magdalena Valley and Llanos basins.
B.4a	**Most significant trends affecting the Company and its industry**	Prices and markets for oil and natural gas are unpredictable and tend to fluctuate significantly, which could impact the oil and gas industry and Gran Tierra's profitability and growth. Revenues are derived from the sale of oil, which price is based on world demand, supply, weather, geopolitical unrest, and other factors, all of which are beyond its control. The oil and gas industry is highly competitive. Gran Tierra faces competition from both local and international companies, which impacts its ability to acquire properties, contract for drilling and other oil field equipment and secure trained personnel. Activity in the Colombian oil and gas sector remains steady. As in other countries, drilling and other activities have increased with recent improvements in oil prices. A number of international companies remain active in the country, including in exploration and production, marketing and transportation, oilfield services and other aspects of the industry.
B.5	**Group structure**	The Company is the parent company of the Group. As at the Latest Practicable Date, the Company has the following direct and indirect subsidiaries: **Name[(1)]** — **Jurisdiction of Incorporation** Gran Tierra Callco ULC — Alberta, Canada Petrolifera Petroleum (Colombia) Limited — Cayman Islands Gran Tierra Energy Cayman Islands Inc. — Cayman Islands Gran Tierra Energy Canada ULC — Alberta, Canada Argosy Energy LLC — Delaware, U.S. Gran Tierra Energy Mexico Holdings 1 LLC — Delaware, U.S. Gran Tierra Energy Mexico Holdings 2 LLC — Delaware, U.S.

		Gran Tierra Energy Colombia, Ltd.	Utah, U.S.
		Gran Tierra Resources Limited	Alberta, Canada
		Gran Tierra Energy International Holdings Ltd	Cayman Islands
		Gran Tierra Luxembourg Holdings S.a.r.l. (*in liquidation*)	Luxembourg
		Gran Tierra Colombia Inc.	Cayman Islands
		Suroco Energy Venezuela	Venezuela
		Vetra Petroamerica P&G Corp.(2)	Barbados
		Southeast Investment Corporation(3)	Panama
		Gran Tierra (PUT-7) Limited	Cayman Islands
		Petrolatina Energy Limited (*in liquidation*)	United Kingdom
		Petrolatina (CA) Limited (*in liquidation*)	United Kingdom
		R.L. Petroleum Corp.	Panama
		North Riding Inc.	Panama
		Petroleos Del Norte S.A. (*in liquidation*)	Colombia
		Taghmen Colombia S.L.	Spain
		Taghmen Argentina Limited (*in liquidation*)	United Kingdom
		Gran Tierra México Energy. S. de R. de C.V.	Mexico

Notes:

(1) All subsidiaries are wholly-owned subsidiaries unless otherwise indicated.

(2) 72.5% ownership by Gran Tierra Colombia Inc. The remaining 27.5% is owned by Vetra Southeast S.L. (not a member of the Group).

(3) *Direct Ownership*: Vetra Petroamerica P&G Corp. 67.67%; Vetra Southeast S.L. (not a member of the Group) 32.33%. *Indirect Ownership*: Gran Tierra 49.06% through interest in Vetra Petroamerica P&G Corp.; Vetra Southeast S.L. (not a member of the Group) 50.94% through a 32.33% direct ownership and an 18.61% indirect interest through Vetra Petroamerica P&G Corp.

B.6	**Interests in shares/ voting rights/ controllers**	As at the Latest Practicable Date, or, where indicated, the date set forth in the footnotes to the table below, in so far as is known to the Company and except as disclosed below, no person is, directly or indirectly, interested in five per cent. or more of the outstanding shares of Common Stock. **Shareholder** / **Number of Shares** / **Percentage of issued share capital** GMT Capital Corp.[1] / 63,925,906 / 16.3% Luminus Management, LLC[2] / 20,788,164 / 5.3% **Notes**: (1) Based on information on SEDI filed on 11 September 2018. (2) Based on a Form 13F filed on EDGAR on 14 August 2018. Other than as set out above, the Company is not aware of any person or persons who could, directly or indirectly, jointly or severally, exercise control over the Company. There are no different voting rights for any holder of shares of Common Stock.
B.7	**Selected historical key financial information**	The tables below summarise certain key financial information relating to the Group for the periods indicated and should be read together with the whole of this Prospectus. The selected key historical financial information set out below has been extracted without material adjustment from (a) the Company's consolidated financial statements as at 31 December 2017 and 31 December 2016 and for the three years ended 31 December 2017, (b) the Company's consolidated financial statements as at 31 December 2016 and 31 December 2015 and for the three years ended 31 December 2016, and (c) the Company's unaudited consolidated financial statements for the six month periods ended 30 June 2017 and 2018.

Summary Consolidated Statements of Operations

	Years ended 31 December		
	2017	**2016**	**2015**
	(*In thousands, except per share data*)		
OIL AND NATURAL GAS SALES	$ 421,734	$ 289,269	$ 276,011
EXPENSES			
Operating	109,869	86,925	75,565
Transportation	25,107	31,776	40,204
Depletion, depreciation and accretion	131,335	139,535	176,386
Asset impairment	1,514	616,649	323,918
General and administrative	39,014	33,218	32,353
Severance	1,287	1,319	8,990
Transaction	-	7,325	-
Equity tax	1,224	3,098	3,769
Foreign exchange loss (gain)	2,067	(1,469)	(17,242)
Financial instruments loss	15,929	10,279	2,027
Other gain	-	-	(502)
Interest expense	13,882	14,145	-
	341,228	942,800	645,468
(LOSS) ON SALE AND GAIN ON ACQUISITION	(44,385)	929	-
INTEREST INCOME	1,209	2,368	1,369
INCOME (LOSS) BEFORE INCOME TAXES	37,330	(650,234)	(368,088)
INCOME TAX EXPENSE (RECOVERY)			
Current	24,322	20,122	15,383
Deferred	44,716	(204,791)	(115,442)
	69,038	(184,669)	(100,059)
NET LOSS AND COMPREHENSIVE LOSS	$ (31,708)	$ (465,565)	$ (268,029)
NET LOSS PER SHARE - BASIC AND DILUTED			
- BASIC AND DILUTED	$ (0.08)	$ (1.45)	$ (0.94)
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC AND DILUTED	396,683,593	320,851,538	285,333,869

	Six months ended 30 June (unaudited)	
	2018	2017
	(*In thousands, except per share data*)	
OIL AND NATURAL GAS SALES	$ 301,674	$ 190,787
EXPENSES		
Operating	61,324	51,145
Transportation	13,519	13,434
Depletion, depreciation and accretion	86,068	58,689
General and administrative	24,373	18,225
Equity tax	-	1,224
Foreign exchange loss	982	2,050
Financial instruments loss (gain)	11,714	(6,886)
Interest expense	12,870	6,426
	210,850	144,307
LOSS ON SALE	(292)	(9,076)
INTEREST INCOME	1,396	653
INCOME BEFORE INCOME TAXES	91,928	38,057
INCOME TAX EXPENSE		
Current	17,116	9,189
Deferred	36,651	22,904
	53,767	32,093
NET INCOME AND COMPREHENSIVE INCOME	$ 38,161	$ 5,964
NET INCOME (LOSS) PER SHARE - BASIC AND DILUTED		
- BASIC AND DILUTED	$ 0.10	$ 0.01
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC	391,173,460	398,795,023
WEIGHTED AVERAGE SHARES OUTSTANDING - DILUTED	427,242,014	398,816,091

Summary Consolidated Balance Sheets

	As at 30 June 2018 (Unaudited)	As at 31 December 2017	2016	2015
		(*In thousands*)		
Cash and cash equivalents	$ 125,807	$ 12,326	$ 25,175	$ 145,342
Total current assets	302,369	145,245	131,685	234,440
Total property and equipment, net	1,178,196	1,099,224	1,066,609	788,993
Total other long-term assets	141,520	185,150	169,602	122,685
Total assets	1,622,085	1,429,619	1,367,896	1,146,118
Total current liabilities	169,438	156,969	155,029	73,991
Total long-term liabilities	477,358	336,315	353,880	70,485
Total shareholders' equity	975,289	936,335	858,987	1,001,642
Total liabilities and shareholders' equity	$ 1,622,085	$1,429,619	$1,367,896	$1,146,118

Summary Consolidated Statements of Cash Flows

	Year ended 31 December 2017	2016	2015
		(*In thousands*)	
Net cash provided by (used in):			
Operating activities	$ 189,644	$ 93,042	$ 62,305
Investing activities	(243,803)	(605,932)	(233,483)
Financing activities	39,127	407,052	(9,277)
Net decrease in cash, cash equivalents and restricted cash and cash equivalents	(16,589)	(105,484)	(186,971)
Cash, cash equivalents and restricted cash and cash equivalents, end of year	$ 26,678	$ 43,267	$ 148,751

	Six Months Ended 30 June 2018	2017
	(*In thousands, unaudited*)	
Net cash provided by (used in):		
Operating activities	$ 130,934	$ 67,536
Investing activities	(166,330)	(95,881)
Financing activities	139,712	55,304
Net increase in cash, cash equivalents and restricted cash and cash equivalents	104,247	25,784
Cash, cash equivalents and restricted cash and cash equivalents, end of period	$ 130,925	$ 69,051

		The Group's revenue during the period covered by the historical financial information was mainly derived from oil sales from its producing assets in Colombia. For the year ended 31 December 2017, 98% (year ended 31 December 2016 – 97%; year ended 31 December 2015 – 97%) of the Group's revenue and other income was generated in Colombia. As of 31 December 2017, the Group had estimated proved reserves NAR of 59.3 MMBOE, of which 67% were proved developed reserves and 99% were oil. During 2016, the Group completed acquisitions of Petroamerica, PGC and PetroLatina, strengthening the Group's position in Colombia. During 2017, the Group completed the sale of its assets in Brazil and Peru to focus on its portfolio of assets in Colombia, while acquiring an interest in PetroTal Corp. (the purchaser of the Group's Peruvian assets), resulting in the Group holding approximately 46% of PetroTal's issued and outstanding commons shares. Revenues from oil and natural gas sales have increased during each year covered by the historical financial information, from $276.0 million in the year ended 31 December 2015 to $289.3 million in the year ended 31 December 2016 to $421.7 million in the year ended 31 December 2017. In the six months ended 30 June 2018, revenue from oil and natural gas sales was $301.7 million (six months ended 30 June 2017 - $190.8 million). The increase in oil and gas sales between 2015 and 2016 was due primarily to the effect of increased sales volumes, partially offset by decreased average oil prices. The increase between 2016 and 2017, and the increase in the six months ended 30 June 2018 compared to the same period in 2017, were due to the combined effect of increased sales volumes and realised oil prices. In the six months ended 30 June 2018, the Group achieved record Colombia working interest production before royalties of 35,239 BOEPD. Production increased largely because of production from development activities in the Acordionero Field. During the period under review, the Group has also had continued significant exposure to oil price strength with oil representing 100% of the Group's production in the six months ended 30 June 2018. Operating expenses during the period covered by the historical financial information increased primarily due to higher sales volumes. Operating expenses per BOE decreased by 13%, from $11.34 to $9.92, between 2015 and 2016, primarily due to Colombian operating cost savings, partially offset by the effect of the weakening of the U.S. dollar against local currencies in South America. Operating expenses per BOE increased by $1.36 BOE from 2016 to 2017, primarily as a result of power disruptions in the Putumayo region relating to the Mocoa natural disaster and NaturAmazonas reforestation and conservation expenses. Colombian operating expenses per BOE increased by $1.12 in the six months ended 30 June 2018 compared with the corresponding period of 2017. Workover expenses decreased by $0.27 over the same period. Excluding workover expenses, Colombia operating expenses increased by $1.39 per BOE primary as a result of payments triggered by renegotiating the Group's field operating agreements, power generation costs, equipment rental and accelerated maintenance costs mainly in the Acordionero field during the second quarter of 2018. Transportation expenses per BOE generally decreased between 2015 and 2017, from $6.03 in 2015 to $3.62 in 2016 to $2.58 in 2017. These decreases in transportation expenses per BOE were primarily due to an increasing percentage of volumes sold at wellhead, and the use of

		alternative transportation routes with lower costs per BOE. Transportation expenses for the six months ended 30 June 2018 decreased from $2.90 to $2.71 per BOE due to renegotiation of certain sales contracts, which had lower transportation costs compared to contracts used in 2017. There has been no significant change in the Group's financial or trading position since 30 June 2018, being the latest date to which the Company's historical financial information in this Prospectus was prepared.
B.8	**Selected key pro forma financial information**	Not applicable. There is no pro forma information included in this Prospectus.
B.9	**Profit forecast/ estimate**	Not applicable. There are no profit forecasts or estimates in this Prospectus.
B.10	**Qualifications on audit report**	Not applicable. There are no qualifications included in the auditor's reports on the historical financial information included in this Prospectus.
B.11	**Working capital qualifications**	Not applicable. In the opinion of the Company, the working capital available to the Group is sufficient for its present requirements, that is, for at least the next 12 months from the date of this Prospectus.

Section C – Securities		
C.1	**Description of securities**	The Company's shares of Common Stock are currently listed on the NYSE American and on the TSX, in each case under the ticker symbol "GTE". On Admission, the shares of Common Stock will be registered with ISIN US38500T1016 and SEDOL number B09R9V5. The Company's ticker symbol will be "GTE".
C.2	**Currency of the securities issue**	The shares of Common Stock are denominated in U.S. dollars.
C.3	**Number of shares/ whether fully paid/ par value**	As at the Latest Practicable Date prior to the publication of this Prospectus, the issued and outstanding share capital of the Company is $10,296,511 comprising 391,316,489 shares of Common Stock, par value of $0.001 per share (all of which were fully paid).
C.4	**Rights attached to the securities**	The Common Stock rank *pari passu* in all respects with each other. The holders of shares of Common Stock are entitled to one vote for each share on all matters submitted to a stockholder vote and have equal rights to participate in capital, dividend and profit distributions by the Company. The holders of Common Stock have no pre-emptive rights, no conversion rights, and there are no redemption provisions applicable to the shares.
C.5	**Restrictions on free transferability**	Not applicable. There are no restrictions on the free transferability of the Common Stock.

C.6	**Admission to trading on regulated market**	Applications have been made (a) to the FCA for all of the shares of Common Stock to be admitted to listing on the standard listing segment of the Official List of the FCA and (b) to the London Stock Exchange for such shares of Common Stock to be admitted to trading on the London Stock Exchange's main market for listed securities. The shares of Common Stock are currently admitted to trading on the NYSE American and on the TSX and, following Admission, will continue to be listed on the NYSE American and on the TSX. No application has been made or is currently intended to be made for the shares of Common Stock to be admitted to listing or trading on any other exchange.
C.7	**Dividend policy**	The Company has never declared or paid dividends on the shares of Common Stock. The Company intends to retain future earnings, if any, to support the development of the business and therefore does not anticipate paying cash dividends for the foreseeable future. Payment of future dividends, if any, would be at the discretion of the Board 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 Revolving Credit Facility, the Company is limited in its ability to pay dividends to Shareholders without the approval of the lending banks.

Section D – Risks		
D.1	**Key information on the key risks specific to the issuer or its industry**	• Prices and markets for oil and natural gas are unpredictable and tend to fluctuate significantly, which could reduce the Group's profitability, growth and value. Future decreases in the prices of oil and gas or sustained low prices may have a material adverse effect on the Group's financial condition, its future results of operations (including rendering existing projects unprofitable), financing available to the Group, and quantities of reserves recoverable on an economic basis, as well as the market price for the Company's securities. • Estimates of oil and natural gas reserves may be inaccurate and the Group's actual revenues may be lower than estimated. Drilling wells may involve significant costs that may be more than estimated and may not achieve the results expected. • Oil and natural gas exploration involves a high degree of operational and financial risk. It is difficult to predict the results and to project the costs of implementing an exploratory drilling program. 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. If the Group is unable to find, develop and acquire additional oil and gas reserves that are economically recoverable, this may adversely affect the Group's financial condition and its results of operations. • The Group is dependent on obtaining and maintaining permits and licences from various governmental authorities. Oil and gas exploration and production operations are subject to complex and stringent laws and regulations, requiring the Group to obtain and maintain numerous licences, permits,

		approvals and certificates. The Group may not be able to obtain, sustain or renew such licences or permits on a timely basis or at all, which could have a material adverse effect on the Group's ability to develop and explore on its properties. • The Group's business is subject to local legal, social, political and economic factors that are beyond the control of the Group and which could impair or delay the Group's ability to expand its operations or operate profitably. The Group operates its business in Colombia, where all of its reserves and production are currently located. Colombia has experienced and may in the future experience political and economic instability. Any changes in oil and gas or investment regulations and policies or a shift in political attitudes in Colombia are beyond the control of the Group and may significantly hamper its ability to expand its operations or operate its business at a profit. • The Group is vulnerable to risks associated with geographically concentrated operations. Currently all of the Group's reserves and production are located in Colombia. Due to the concentrated nature of the Group's portfolio of properties, a number of its properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on the Group's results of operations than they might have on other companies that have a more diversified portfolio of properties. • Social disruptions or community disputes in areas of operations of the Group may delay production and result in lost revenue. Colombia has a history of security problems. If these security problems disrupt the Group's operations, the Group's financial condition and results of operations could be adversely affected. • Colombia has a history of security problems and violent conflict with guerrilla groups. The Group's efforts to ensure the security of its physical assets may not be successful and there can also be no assurance that the Group can maintain the safety of field personnel of the Group or the Group's contractors, the Group's Bogota head office personnel or operations in Colombia, or that this violence will not adversely affect the Group's operations in the future and cause significant loss. • Environmental regulation and risks may adversely affect the Group's business. Environmental regulation is stringent and costs and expenses of regulatory compliance are increasing. All phases of the oil and gas business present environmental risks and hazards. 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 the Group's insurance coverage may be inadequate or unavailable.

D.3	**Key information on the key risks specific to the securities**	• The proposed standard listing of the Common Stock will afford investors a lower level of regulatory protection than a premium listing. • An active trading market in the UK for the Common Stock may not develop or be sustained. If an active trading market in the UK is not developed or maintained, the liquidity and trading price of the Common Stock in the UK could be adversely affected. The trading price of the Common Stock in the UK may be subject to wide fluctuations in response to many factors, including the price of oil, short-term selling pressures, equity market fluctuations, general economic conditions and regulatory changes which may adversely affect the market price of the Common Stock in the UK, regardless of the Group's actual performance or conditions in its key markets. As a result of fluctuations in the market price of the Common Stock, investors may not be able to sell their Common Stock at or above the price at which they were purchased, or at all. • The Company does not currently intend to pay dividends and its ability to pay dividends in the future may be limited. As a result, investors may not receive any return on an investment in the Common Stock unless they sell such Common Stock for a price greater than that which they paid for them. • Substantial future sales of Common Stock could impact their market price. • The market price of the Common Stock may fluctuate significantly in response to a number of factors, many of which will be out of the Group's control. The market price of the Common Stock may prove to be highly volatile, which may prevent Shareholders from being able to sell their Common Stock at or above the price they paid for them. • Following Admission, the Common Stock will be listed on the NYSE American, the TSX and the London Stock Exchange and investors seeking to take advantage of price differences between such markets may create unexpected volatility in market prices. • Future issues of new shares of Common Stock may dilute the holdings of Shareholders. • Holders of CDIs must rely on CREST International Nominees Limited to grant such CDI holders the right to exercise rights attaching to the underlying shares of Common Stock. Holders of CDIs may experience delays in receiving any proxy forms and may have to act earlier than other Shareholders when casting votes at general meetings of the Company, by virtue of the administrative process involved in connection with holding CDIs. • The rights afforded to Shareholders are governed by the laws of the State of Delaware and non- U.S. shareholders may have difficulties exercising rights which are governed by such laws.

Section E – Offer		
E.1	**Total net proceeds of the issue/offer and estimated expenses**	Not applicable. There is no offer of the Company's securities.
E.2a	**Reasons for the offer and use of proceeds**	Not applicable. There is no offer of the Company's securities.
E.3	**Terms and conditions of the offer**	Not applicable. There is no offer of the Company's securities.
E.4	**Material/conflicting interests**	Not applicable. There is no offer of the Company's securities.
E.5	**Name of the person or entity offering to sell the security/ lock-up arrangements**	Not applicable. There is no offer of the Company's securities.
E.6	**Dilution**	Not applicable. There is no offer of the Company's securities.
E.7	**Estimated expenses charged to the investor**	Not applicable. No expenses will be charged to investors by the Company.

RISK FACTORS

Any investment in the Common Stock is subject to a number of risks. Accordingly, prior to making any investment decision, prospective investors should carefully consider all the information contained in this Prospectus including, in particular, the risk factors described below.

Prospective investors should note that the risks relating to the Group, its industry and the Common Stock summarised in the section of this Prospectus headed "Summary" are the risks that the Directors believe to be the most essential to an assessment by a prospective investor of whether to invest in the Common Stock. However, as the risks which the Group faces relate to events and depend on circumstances that may or may not occur in the future, prospective investors should consider not only the information on the key risks summarised in the section of this Prospectus headed "Summary" but also, among other things, the risks and uncertainties described below.

The risks and uncertainties described below represent those the Directors consider to be material as at the date of this Prospectus. However, these risks and uncertainties are not an exhaustive list or explanation of all risks. Additional risks and uncertainties relating to the Group that are not currently known to it, or that the Group currently deems immaterial, may individually or cumulatively also have a material adverse effect on the Group's business, prospects, results of operations and financial condition and, if any or a combination of such risks should occur, the price of Common Stock may decline and investors could lose all or part of their investment. Investors should consider carefully whether an investment in the Common Stock is suitable for them in the light of the information in this Prospectus and their personal circumstances.

1. RISKS RELATING TO THE GROUP'S BUSINESS AND THE INDUSTRY IN WHICH IT OPERATES

1.1 Prices and markets for oil and natural gas are unpredictable and tend to fluctuate significantly, which could reduce the Group's profitability, growth and value.

Substantially all of the Group's revenues are derived from the sale of oil, which price is based on world demand, supply, weather, pipeline capacity constraints, inventory storage levels and other factors, geopolitical unrest, all of which are beyond the Group's control. Historically, the market for oil has been volatile, and the market is likely to continue to be volatile in the future. Furthermore, prices which the Group receives for its oil sales, while based on international oil prices, are established by contracts with purchasers with prescribed deductions for transportation and quality differentials. These differentials can change over time and have a detrimental impact on realised prices.

Future decreases in the prices of oil and gas or sustained low prices may have a material adverse effect on the Group's financial condition, its future results of operations (including rendering existing projects unprofitable), financing available to the Group, and quantities of reserves recoverable on an economic basis, as well as the market price for the Company's securities.

1.2 Estimates of oil and natural gas reserves may be inaccurate and the Group's actual revenues may be lower than estimated.

The Group makes estimates of oil and natural gas reserves, upon which it bases its financial projections and capital expenditure plans. These reserve estimates are made 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 the Group's reserve estimates relies in part on the ability of the management team, engineers and other advisors to make accurate assumptions. Drilling wells may involve significant costs that may be more than estimated and may not achieve the results expected. Economic factors beyond the Group's control, such as world oil prices, interest rates, inflation, and exchange rates, will also impact the quantity and value of the Group's reserves.

The process of estimating oil and gas reserves is complex, and requires the use of significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each property. As a result, the Group's 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 per cent 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 gas reserves may vary substantially from those estimated. Such changes could result in a material reduction to the Group's revenues and could result in the impairment of the Group's oil and natural gas interests.

1.3 Unless the Group is able to replace its reserves and production, and develop and manage oil and gas reserves and production on an economically viable basis, the Group's financial condition and results of operations will be adversely impacted.

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

Exploration, development and production costs (including transportation and workover costs), marketing costs (including distribution costs) and regulatory compliance costs (including taxes) will substantially impact the net revenues the Group derives from the oil and gas that it produces. These costs are subject to fluctuations and variations in different locales in which the Group operates, and the Group may not be able to predict or control these costs. If these costs exceed the Group's expectations, this may adversely affect the Group's results of operations.

The Group's future reserves will depend not only on its ability to develop and effectively manage then-existing properties, but also on its ability to identify and acquire additional suitable producing properties or prospects, to find markets for the oil and natural gas the Group develops and to effectively distribute its production into the Group's markets.

1.4 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 to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions, such as over-pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

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. If the Group is unable to find, develop and acquire additional oil and gas reserves that are economically recoverable, this may adversely affect the Group's financial condition and its results of operations.

1.5 The Group's business requires significant capital expenditures, and the Group may not have the resources necessary to fund these expenditures.

The Group generally seeks to fund its capital programme through cash flows from operations and expects this to be the case for the Group's capital programme through the medium term. The Group's capital programme for 2018 is intended to be $305 to $325 million for exploration and development.

This does not include the cost of any acquisitions. In line with the Group's general policy, the Group expects to finance its 2018 capital programme fully through cash flows from operations. Funding this capital programme from cash flow from operations relies in part on oil prices remaining at or near the Company's forecast of $72 per barrel.

The Group operates over 90% of its production and owns 100% of most of its assets and has significant ability to decrease or increase capital expenditures as it sees fit. However, without prejudice to the working capital statement in paragraph 14 of Part VII (*Additional Information*), if cash flows from operations, cash on hand and available capacity under the Revolving Credit Facility are not sufficient to fund its capital programme, the Group would be required to either seek external financing or to delay or reduce its exploration and development activities, which could impact production and reserve growth.

If additional capital is required, the Group may pursue sources of capital through various financing transactions or arrangements, including joint venturing of projects, debt financing, equity financing or other means. The Group may not be able to access capital on favourable terms or at all. If the Group succeeds in raising additional capital, future financings may be dilutive to Shareholders, as this may involve the issue of additional shares of Common Stock or other equity to investors. In addition, debt and other mezzanine financing may involve a pledge of assets, involve covenants that would restrict the Group's business activities, and may be senior to interests of equity holders. The Group may incur substantial costs in pursuing future capital financing, including investment banking fees, legal fees and other costs. The Group may also be required to recognise non-cash expenses in connection with certain securities it may issue, such as convertibles and warrants, which would adversely impact the Group's financial results.

The Group's 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 its oil and natural gas properties in South America, 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 the Group's revenues will likely decrease, and such decreased revenues may increase its requirements for capital. Some of the contractual arrangements governing the Group's exploration activity require it to commit to certain capital expenditures, and the Group may lose its contract rights if it does not have the required capital to fulfil these commitments. If the amount of capital the Group is able to raise from financing activities, together with its cash flow from operations, is not sufficient to satisfy its capital needs (even to the extent that the Group reduces its activities), the Group may be required to curtail its operations.

1.6 **The borrowing base under the Revolving Credit Facility may be reduced by the lenders, which could prevent the Group from meeting its future capital needs.**

The borrowing base under the Revolving Credit Facility is currently $300 million and the maturity of the facility is November 2020. The Group's borrowing base is re-determined by the lenders twice per year, and will be re-determined no later than November 2018. The Group's 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, the issuance of new indebtedness or for any other reason. The Group cannot be certain that funding will be available if needed, and to the extent required, on acceptable terms. Without prejudice to the working capital statement in paragraph 14 of Part VII (*Additional Information*), in the event of a decrease in its borrowing base, the Group could be required to repay any indebtedness in excess of the re-determined borrowing base, which could deplete cash flow from operations or require additional financing.

Further, the Group's borrowing base is made available subject to the terms and covenants of the 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 the Group to repay a portion of its borrowings and suffer adverse financial impacts.

1.7 **The Group's business is subject to local legal, social, political and economic factors that are beyond the control of the Group and which could impair or delay the Group's ability to expand its operations or operate profitably.**

The Group operates its business in Colombia, where all of its reserves and production are currently located, and may eventually expand to other countries. Exploration and production operations are subject to legal, social, political and economic uncertainties, including terrorism, military repression, social unrest and activism, strikes by local or national labour 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 the operations of the Group and threaten the economic viability of its projects or the Group's ability to meet its production targets.

Colombia has experienced and may in the future experience political and economic instability. This instability could result in new governments or the adoption of new policies, laws or regulations that might assume a substantially more hostile attitude toward foreign investment, including but not limited to: the imposition of additional taxes; nationalisation; 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. National elections were recently concluded in Colombia and the newly elected president commenced his term on 7 August 2018. Any changes in oil and gas or investment regulations and policies or a shift in political attitudes in Colombia or other countries in which the Group may operate in the future are beyond the control of the Group and may significantly hamper its ability to expand its operations or operate its business at a profit.

1.8 **The Group is vulnerable to risks associated with geographically concentrated operations.**

Currently all of the Group's reserves and production are located in Colombia and the vast majority of the Group's production comes from three fields. For the year ended 31 December 2017, the Acordionero, Costayaco and Moqueta Fields collectively generated 82% of the Group's production and at 31 December 2017, these three fields accounted for 81% of the Group's proved reserves. As a result of this concentration, the Group may be disproportionately exposed to the impact of, among other things, regional supply and demand factors including limitations on its ability to most profitably sell or market the Group's oil and gas 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 authorisation 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 the Group's portfolio of properties, a number of its properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on the Group's results of operations than they might have on other companies that have a more diversified portfolio of properties.

The Group relies on local infrastructure and the availability of transportation for storage and shipment of its products. This infrastructure, including storage and transportation facilities, is less developed than that in North America and may be insufficient for the Group's needs at commercially acceptable terms in the localities in which it operates. Further, the Group operates 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 and could lead to operational delays which could affect the Group's ability to add to its reserve base or produce oil, or serious injury or loss of life and could have a significant impact on its reputation or cash flow. Additionally, some of this equipment is specialised and may be difficult to obtain in areas of operations of the Group, which could hamper or delay operations, and could increase the cost of those operations.

1.9 **Social disruptions or community disputes in areas of operations of the Group may delay production and result in lost revenue.**

To enjoy the support and trust of local populations and governments, the Group 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 in operations, loss of license or major impact to the Group's reputation in these communities, which could adversely affect its business. For example, in 2017, the exploration drilling program at Prosperidad-1 in the Llanos basin was postponed due to road blockades and civil disruption along the route to the well site. The Group cannot ensure that similar disruptions will not be experienced in future and the Group cannot predict their potential impacts, which may include delays or loss of production, standby charges, stranded equipment, or damage to the Group's facilities. In addition, the Group must comply with legislative requirements for prior consultation of communities and ethnic groups who are affected by its proposed projects in Colombia. Notwithstanding the Group's compliance with these requirements, the Group may be sued by such communities through a writ for protection or *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, essentially referendums, on extractive industries. The referendums were organised by opponents of the mining or oil and gas industries. To this point all have passed with a large majority voting to prohibit extractive industry activity in the particular region, but it remains unclear to what extent such results are legally binding and take precedence over the issuance of mineral rights by the national government.

1.10 **The Group is dependent on obtaining and maintaining operational permits and licences from various governmental authorities.**

The Group's oil and natural gas exploration and production operations are subject to complex and stringent laws and regulations. In order to conduct its operations in compliance with these laws and regulations, the Group must obtain and maintain numerous operational licences, permits, approvals and certificates, including environmental and other operating permits. The Group may not be able to obtain, sustain or renew such licences and permits on a timely basis or at all. Failure or delay in obtaining regulatory approvals or drilling permits could have a material adverse effect on the Group's ability to develop and explore on its properties, and receipt of drilling permits with onerous conditions could increase the Group's compliance costs. Regulations and policies relating to these licences and permits may change, be implemented in a way that the Group does not currently anticipate or take significantly greater time to obtain. There can be no assurance that future political conditions in Colombia will not result in changes to policies with respect to foreign development and ownership of oil, environmental protection, health and safety or labour relations, which may negatively affect the Group's ability to undertake exploration and development activities in respect of present and future properties, as well as its ability to raise funds to further such activities.

As the Group is not the operator of all the joint ventures it is currently involved in, the Group may rely on the operator to obtain all necessary permits and licences. If the Group fails to comply with these requirements, it could be prevented from drilling for oil and natural gas and be subject to civil or criminal liability or fines. Revocation or suspension of the Group's environmental and operating permits could have a material adverse effect on its business, financial condition and results of operations.

1.11 **Guerrilla activity and security concerns in Colombia may disrupt the Group's operations.**

For over 50 years, the Colombian government was engaged in a conflict with two main Marxist guerrilla groups: the Revolutionary Armed Forces of Colombia (**"FARC"**) and the National Liberation Army (**"ELN"**). Oil pipelines have been primary targets of guerrilla activity. On 26 September 2016, the Colombian government and the FARC signed a peace agreement (the **"Peace Agreement"**) and, on 30 November 2016, the Peace Agreement was ratified by the Colombian government, the result of which was the demobilisation and disarmament of the FARC. A ceasefire negotiated between the ELN and the Colombian government recently ended and it is not currently known whether or to what degree violence will result and whether and to what degree that violence may impact the operations of the

Group. Notwithstanding the Peace Agreement and the continuing attempts by the Colombian government to reduce or prevent activity of guerrilla dissidents, such efforts may not be successful and such activity may disrupt the Group's operations in the future or cause the Group higher security costs and could adversely impact its financial condition, results of operations or cash flows.

Colombia also has a history of security problems. The Group's efforts to ensure the security of its physical assets may not be successful and there can also be no assurance that the Group can maintain the safety of field personnel of the Group or the Group's contractors, the Group's Bogota head office personnel or operations in Colombia, or that this violence will not adversely affect the Group's operations in the future and cause significant loss. If these security problems disrupt the Group's operations, the Group's financial condition and results of operations could be adversely affected.

1.12 **Environmental regulation and risks may adversely affect the Group's business.**

Environmental regulation is stringent and 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 the Group to administrative, civil and criminal fines and penalties. The Group's 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. The Group 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 the Group 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 the Group however they may have a material adverse impact on the Group's business.

Given the nature of the Group's 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 the Group's insurance coverage may be inadequate or unavailable.

1.13 **Most of the Group's revenue is generated outside of Canada and the United States, and if the Group determines to, or is required to, repatriate earnings from foreign jurisdictions, it could be subject to taxes.**

The Company is domiciled in the United States and its head office is in Canada. However, most of the Group's revenue is generated outside of the United States and Canada. The cash generated from operations abroad is generally not available to fund domestic or head office operations unless funds are repatriated. At this time, the Group does not intend to repatriate further funds, other than to pay head office charges, but if it did, the Group 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 unrecognised deferred tax liability on these undistributed earnings is not practicable. On 22 December 2017, the budget reconciliation statute in the United States, commonly referred to as the Tax Cuts and Jobs Act (the **"Tax Act"**), significantly revised U.S. federal corporate income tax law, including the creation of a one-time "transition tax" on a deemed dividend of untaxed accumulated earnings and profits of certain non-U.S. corporations. This deemed dividend does not result in the actual movement of foreign earnings and has no local impact in those non-U.S. jurisdictions. While the Group's analysis of the impact of the Tax Act on the Group's cash tax liability and financial condition has not identified any overall material adverse effect, it is continuing to evaluate the effects of the Tax Act on the Group and there are a number of uncertainties and ambiguities as to the interpretation and application of many of the provisions in the Tax Act. In the absence of guidance on these issues, the Group will use what it believes to be reasonable interpretations and assumptions in applying the Tax Act for purposes of determining its cash tax liabilities and results of operations, which may change as the Group receives additional clarification and implementation guidance. It is possible that the U.S. Internal Revenue Service could issue subsequent guidance or take positions on audit that differ from the interpretations and assumptions that the Group previously made, which could have a material adverse effect on the Group's cash tax liabilities, results of operations and financial condition.

1.14 Foreign currency exchange rate volatility may affect the Group's financial results.

The Group sells its oil and natural gas production under agreements that are denominated mainly in U.S. dollars. Many of the operational and other expenses incurred by the Group, including current and deferred tax liabilities in Colombia, are denominated in Colombian pesos. Most of the Group's administration costs in Canada are incurred in Canadian dollars. As a result, the Group is exposed to translation risk when local currency financial statements are translated to U.S. dollars, its functional currency. An appreciation of local currencies can increase the Group's costs and negatively impact its results from operations. As the Group's Consolidated Financial Statements are presented in U.S. dollars, it is required to 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. The Group is also exposed to transaction risk on settlement of payables and receivables denominated in foreign currency.

1.15 The Group may be exposed to liabilities under anti-bribery laws and a finding that it violated these laws could have a material adverse effect on the Group's business.

The Group is subject to anti-bribery laws in the United States, Canada and Colombia and will be subject to similar laws in other jurisdictions where it may operate in the future. The Group may face, directly or indirectly, corrupt demands by officials, tribal or insurgent organisations, international organisations, or private entities. As a result, the Group faces the risk of unauthorised payments or offers of payments by employees, contractors, agents, and partners of the Group or its affiliates, given that these parties are not always subject to the control or direction of the Group. It is the Group's policy to prohibit these practices. However, the Group's existing safeguards and any future improvements to those measures may prove to be less than effective or may not be followed, and the Group's employees, contractors, agents, and partners may engage in illegal conduct for which it might be held responsible. A violation of any of these laws, even if prohibited by the Group's 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 the Group's business and financial condition.

1.16 If the United States imposes sanctions on Colombia in the future, the Group's 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 of the United States 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 the Group's ability to obtain necessary financing to develop its Colombian properties, and could further heighten the political and economic risks associated with the Group's operations in Colombia.

1.17 The threat and impact of cyberattacks may adversely impact the Group's operations and could result in information theft, data corruption, operational disruption, and/or financial loss.

The Group uses digital technologies and software programs to interpret seismic data, manage drilling rigs, conduct reservoir modelling and reserves estimation, as well as to process and record financial and operating data. The Group depends 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 its employees and business partners, analyse seismic and drilling information, estimate quantities of oil and gas reserves and for many other activities related to the Group's 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. The Group's business processes depend on the availability, capacity, reliability and security of the Group's information technology infrastructure and its ability to expand and continually update this infrastructure in response to the Group's changing needs and therefore it is critical to the Group's business that its facilities and infrastructure remain secure. While the Group has implemented strategies to mitigate impacts from these types of events, there can be no guarantee that measures taken to defend against cybersecurity threats will be sufficient for this purpose. The ability of the information technology function to support the Group's business in the event of a security breach or a disaster such as fire or flood and its 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, the Group 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 the Group's inability to conduct business or perform some business processes in a timely manner. Moreover, if any of these events were to materialise, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities essential to its operations and could have a material adverse effect on the Group's reputation, financial condition or results of operations.

The Group's 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" programmes to the Group's 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 the Group's efforts to mitigate "spoof" and "phishing" emails through education, "spoof" and "phishing" activities remain a serious problem that may damage the Group's information technology infrastructure.

1.18 **Pending regulations related to emissions and the impact of any changes in climate could adversely impact the Group's business.**

Governments around the world have become increasingly focused on regulating greenhouse gas (**"GHG"**) emissions and addressing the impacts of climate change in some manner. Colombia has enacted legislation related to GHG emissions and has also passed legislation requiring the country to generate 77% of its energy from renewable resources and reduce deforestation in the Amazon to zero by 2020.

GHG emissions legislation is emerging and is subject to change. For example, on an international level, in December 2015, almost 200 nations 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. Colombia has signed the Paris Agreement. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact the Group's business, any such future laws and regulations that limit GHG emissions could adversely affect demand for the oil and natural gas produced by the Group.

Current GHG emissions legislation has not resulted in material compliance costs. However, 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 the Group is unable to recover a significant amount of its costs related to complying with climate change regulatory requirements imposed on the Group, it could have a material adverse impact on the Group's business, financial condition and results of operations. In addition, significant restrictions on GHG emissions could result in decreased demand for the oil produced by the Group, with a resulting decrease in the value of the Group's reserves. Further, to the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact the Group's cost of or access to capital. Finally, although the Group strives to operate its 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 the Group serves or the areas where the Group's assets reside, the Group could incur increased expenses, the Group's operations could be materially impacted, and demand for the Group's products could fall.

1.19 **The oil and gas industry is highly competitive.**

The Group faces competition from both local and international companies. This competition impacts the Group's ability to acquire properties, contract for drilling and other oil field equipment and secure trained personnel. Many competitors, such as Ecopetrol, Colombia's national oil company, have greater financial and technical resources. The Group's 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 the Group, which could adversely affect its competitive position. The Group's ability to acquire additional properties and to discover reserves in the future will depend on its ability to evaluate and select suitable properties and to 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 the Group competes to develop and produce those reserves cost effectively. In addition, the Group competes to monetise its oil production: for transportation capacity and infrastructure for the delivery of its products, to maintain a skilled workforce and to obtain quality services and materials. If the Group is unable to compete effectively against its competitors, this could have a material adverse effect on its business, financial condition and results of operations.

1.20 **The Group holds a minority equity investment in PetroTal, and its inability, or limited ability, to control the operations or management of PetroTal may result in its receiving or retaining less than the amount of benefit the Group expects.**

During 2017, the Group completed the sale of its assets in Peru. In connection with the divestiture, Gran Tierra acquired a minority equity interest in PetroTal, the entity that acquired the Peruvian assets, representing approximately 46% of PetroTal's issued and outstanding common shares. In addition, the Company's chief executive officer and chief financial officer serve on the board of directors of PetroTal. Even though the Group is able to exercise influence as a minority equity investor in PetroTal, the Group's influence of PetroTal is limited to its rights under the share purchase agreement and annexes thereto and PetroTal's charter and bylaws. Such limitations include a covenant by certain members of the Group not to exercise any voting rights associated with its shares in PetroTal which exceed 30% of the issued and outstanding common shares of PetroTal. As a result, the Group may be unable to implement or influence PetroTal's business plan, assure quality control, or set the timing and pace of development. The Group's inability, or limited ability, to control the operations or management of PetroTal may result in the Group receiving or retaining less than the amount of benefit it might otherwise expect to receive from such investment. The Group may also be unable, or limited in its ability, to cause PetroTal to effect significant transactions such as large expenditures or contractual commitments, the development of properties, the construction or acquisition of assets or the borrowing of money. Service on the board of directors by two of the Company's senior executive officers will require time commitment and could expose them to liability in such role. If PetroTal or its board of directors were to experience events that exposed them to liability or reputational harm, it could have an adverse effect on the Group or its senior executives, including a decline in the market price of the Company's equity securities.

2. RISKS RELATING TO THE COMMON STOCK

2.1 **The proposed standard listing of the Common Stock will afford investors a lower level of regulatory protection than a premium listing.**

Application has been made for the Common Stock to be admitted to the Standard Listing Segment of the Official List. A standard listing will afford investors in the Company a lower level of regulatory protection than that afforded to investors in a company with a premium listing, which is subject to additional obligations under the Listing Rules. A standard listing will not permit the Company to gain a FTSE indexation, which may have an adverse effect on the valuation of the Common Stock.

2.2 **An active trading market in the UK for the Common Stock may not develop or be sustained.**

There is currently no UK market for the Common Stock. The Common Stock is currently and, following Admission, will continue to be listed on the NYSE American and on the TSX. In addition, application has been made for the Common Stock to be admitted to listing on the Official List of the FCA and to trading on London Stock Exchange's main market for listed securities. However, there can be no assurance that an active trading market in the UK for the Common Stock will develop or, if it does develop, be sustained. If an active trading market in the UK is not developed or maintained, the liquidity and trading price of the Common Stock in the UK could be adversely affected. The trading price of the Common Stock in the UK may be subject to wide fluctuations in response to many factors, including the price of oil, short-term selling pressures, equity market fluctuations, general economic conditions and regulatory changes which may adversely affect the market price of the Common Stock in the UK, regardless of the Group's actual performance or conditions in its key markets. As a result of fluctuations in the market price of the Common Stock, investors may not be able to sell their Common Stock at or above the price at which they were purchased, or at all.

2.3 The Company does not currently intend to pay dividends and its ability to pay dividends in the future may be limited.

The Company has never declared or paid dividends on the shares of Common Stock. The Company currently intends to retain future earnings, if any, to support the development of the business and therefore does not anticipate paying cash dividends for the foreseeable future. Accordingly, there is currently no intention to pay dividends and a dividend may never be paid. Payment of future dividends, if any, would be at the discretion of the Board after taking into account various factors, including current financial condition, the tax impact of repatriating cash, operating results and current and anticipated cash needs. Further, under the terms of the Revolving Credit Facility, the Company is limited in its ability to pay dividends to Shareholders without the approval of the lending banks.

As a result of the foregoing, investors may not receive any return on an investment in the Common Stock unless they sell such Common Stock for a price greater than that which they paid for them.

2.4 Substantial future sales of Common Stock could impact their market price.

The Company cannot predict what effect, if any, future sales or issue of shares of Common Stock, or the availability of shares of Common Stock for future sale, will have on the market price of the Common Stock. The sale or issue of substantial amounts of shares of Common Stock in the public market after Admission, or the perception or any announcement that such sale or issue could occur, could adversely affect the market price of Common Stock and may make it more difficult for investors to sell their shares of Common Stock at a time and price which they deem appropriate, or at all.

2.5 The market price of the Common Stock may fluctuate significantly in response to a number of factors, many of which will be out of the Group's control.

Publicly traded securities from time to time experience significant price and volume fluctuations that may be unrelated to the operating performance of the company that has issued them. In addition, the market price of the Common Stock in the UK may prove to be highly volatile, which may prevent Shareholders from being able to sell their Common Stock at or above the price they paid for them. The market price of the Common Stock in the UK may fluctuate significantly in response to a number of factors, many of which are and will be beyond the Group's control, including the prevailing price of oil and natural gas, variations in operating results in the Group's reporting periods, changes in financial estimates by securities analysts, changes in market valuation of similar companies, strategic actions by competitors, announcements by the Group of significant contracts, acquisitions, results of exploration and development operations, planned investments or other capital commitments, strategic alliances, joint ventures or additions or departures of key personnel, speculation about the Group in the press or the investment community, any changes in legal and regulatory requirements, any shortfall in turnover or net profit or any increase in losses from levels expected by securities analysts, and future issues or sales of Common Stock. Any or all of these events could result in a material decline in the price of the Common Stock in the UK.

2.6 Following Admission, the Common Stock will be listed on the NYSE American, the TSX and the London Stock Exchange and investors seeking to take advantage of price differences between such markets may create unexpected volatility in market prices.

The Common Stock is currently listed on the NYSE American and the TSX. Following Admission, the Common Stock will also be listed and traded on the London Stock Exchange. 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 London Stock Exchange 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 the Company's transfer agent or registrar. This could result in time delays and additional cost for Shareholders.

2.7 Future issues of new shares of Common Stock may dilute the holdings of Shareholders.

Although there are no new shares of Common Stock being offered as part of the Admission, it is possible, that the Company may decide to offer new shares of Common Stock or securities convertible into Common Stock in the future, to raise financing to fund future acquisitions and other growth opportunities, invest in its business for general corporate purposes or for other purposes. Subject to any applicable pre-emption rights, any future issues of shares of Common Stock may have a dilutive effect on the holdings of Shareholders and could have a material adverse effect on the market price of the Common Stock in the UK.

2.8 Holders of CDIs must rely on CREST International Nominees Limited to grant such CDI holders the right to exercise rights attaching to the underlying shares of Common Stock.

Securities issued by non-UK companies, such as the Company, cannot be held or transferred electronically in the CREST system. On Admission, holders of Common Stock who choose to settle interests in the Common Stock through the CREST system will be issued with dematerialised CREST depositary interests (**"CDIs"**) representing entitlements to shares of Common Stock. The shares of Common Stock will not themselves be admitted to CREST. While holders of CDIs will have an interest in the underlying shares of Common Stock, they will not be the registered holders of the shares of Common Stock.

The registered holder of shares of Common Stock represented by CDIs will be Cede & Co, a nominee of DTC. The custodian of the shares of Common Stock will be CREST International Nominees Limited, who will hold them through DTC either directly or through a sub-custodian as nominee for CREST Depository Limited. CREST Depository Limited will hold those shares of Common Stock on trust (as bare trustee under English law) for the shareholders who elect to hold their interests in the Common Stock in uncertificated form through the CREST system, to whom it will issue CDIs. Although the Company will enter into arrangements to enable it to send out notices of shareholder meetings and proxy forms to its CDI holders and pursuant to the omnibus proxy arrangements of Cede & Co and Euroclear, CREST International Nominees Limited (the custodian of the shares of Common Stock underlying the CDIs) will be able to, subject to certain requirements, give each beneficial owner of a Depositary Interest the right to vote directly in respect of such owner's underlying shares of Common Stock, there can be no assurance that such information and, consequently, all such rights and entitlements will at all times be duly and timely passed on or that such proxy arrangements will be effective.

The Company intends to establish a depositary interest facility with a third party depositary as soon as practicable following Admission. Pursuant to these arrangements, Depositary Interests representing shares of Common Stock will be issued and held on trust for holders of the Depositary Interests by such third party depositary. Once the depositary interest facility is set up, the CDIs will be cancelled and transferred to the third party depositary, who will issue to CDIs holders at the time of cancellation Depositary Interests in respect of their underlying holding of shares of Common Stock. Similar to CDIs the depositary will be the registered shareholder of the shares of Common Stock underlying the Depositary Interests and will have the power to exercise voting and other rights conferred on behalf of the relevant holder. Consequently, the holders of Depositary Interests, once constituted, must rely on the depositary to exercise such rights for the benefit of the relevant holder. It is expected that the Depositary will be able to, pursuant to omnibus proxy arrangements of Euroclear subject to certain requirements, give each beneficial owner of a Depositary Interest the right to vote directly in respect of such owner's underlying shares of Common Stock. However, there can be no assurance that all such rights and entitlements will at all times be duly and timely passed on or that such proxy arrangements will be effective.

Holders of CDIs and, when constituted, holders of Depositary Interests, may experience delays in receiving any proxy forms and may have to act earlier than other Shareholders when casting votes at general meetings of the Company, by virtue of the administrative process involved in connection with holding CDIs or, when constituted, Depositary Interests.

2.9 **The rights afforded to Shareholders are governed by the laws of the State of Delaware and non- U.S. shareholders may have difficulties exercising rights which are governed by such laws.**

As the Company is a Delaware corporation, the rights of Shareholders will be governed by the laws of the State of Delaware and the Bylaws. The rights of Shareholders under the laws of the State of Delaware may differ from the rights of shareholders of companies incorporated in other jurisdictions. Not all rights available to shareholders under English law will be available to the Shareholders.

Further, the rights and obligations of the Company's shareholders are regulated by corporate law of the State of Delaware and Shareholders must follow the requirements of such laws in order to exercise their rights, in particular the resolutions of the shareholders in general meeting may be passed with majorities different from the majorities required for the adoption of equivalent resolutions under English law or other laws. Shareholders do not have pre-emptive rights and the Company may issue a large amount of additional shares generally without Shareholders' consent. Additionally, to the extent that pre-emptive rights are granted, shareholders in the Company in some jurisdictions may experience difficulties or may be unable to exercise their pre-emptive rights. Should the Company's share capital be increased in the future, Shareholders who will not exercise their priority right to subscription of new shares should take into account that their interest in the Company's share capital may be diluted upon the issuance of new shares of Common Stock.

IMPORTANT INFORMATION

1. GENERAL

No person has been authorised to give any information or to make any representations in connection with Admission other than those contained in this Prospectus and, if given or made, such information or representation must not be relied upon as having been authorised by or on behalf of the Company, the Directors or RBC Capital Markets.

No representation or warranty, express or implied, is made by the Company, the Directors or RBC Capital Markets as to the accuracy or completeness of such information, and nothing contained in this Prospectus is, or shall be relied upon as, a promise or representation by the Company, the Directors or RBC Capital Markets as to the past, present or future. Without prejudice to any obligation of the Company to publish a supplementary prospectus pursuant to section 87G of FSMA and paragraph 3.4.1 of the Prospectus Rules, neither the delivery of this Prospectus nor any distribution of Common Stock shall, under any circumstances, create any implication that there has been no change in the business or affairs of the Group since the date hereof or that the information contained herein is correct as of any time subsequent to the earlier of the date hereof and any earlier specified date with respect to such information.

The contents of this Prospectus are not to be construed as legal, financial, business or tax advice. Each prospective investor should consult his or her or its own lawyer, financial adviser or tax adviser for legal, financial, business or tax advice in relation to any purchase or proposed purchase of the Common Stock. Each prospective investor should consult with such advisers as needed to make his or her or its investment decision and to determine whether it is legally permitted to hold shares of Common Stock under applicable legal, investment or similar laws or regulations. None of the Company, the Directors or RBC Capital Markets or any of their representatives is making any representation to any purchaser of the Common Stock regarding the legality of an investment by such purchaser.

Investors should be aware that they may be required to bear the financial risks of any investment in the Common Stock for an indefinite period of time.

This Prospectus is not intended to provide the basis of any credit or other evaluation and should not be considered as a recommendation by any of the Company, the Directors, RBC Capital Markets or any of their respective representatives that any recipient of this Prospectus should subscribe for or purchase shares of Common Stock. Prior to making any decision whether to subscribe for or purchase any shares of Common Stock, prospective investors should ensure that they have read this Prospectus in its entirety and, in particular, the section titled "*Risk Factors*", and not just rely on key information or information summarised in it. In making an investment decision, prospective investors must rely upon their own examination of the Group and the Common Stock including the merits and risks involved.

Recipients of this Prospectus may not reproduce or distribute this Prospectus, in whole or in part, and may not disclose any of the contents of this Prospectus or use any information herein for any purpose other than considering the Admission. Such recipients of this Prospectus agree to the foregoing by accepting delivery of this Prospectus.

2. PRESENTATION OF FINANCIAL INFORMATION

Unless otherwise indicated, the historical financial information included in this Prospectus has been prepared in accordance with generally accepted accounting principles in the United States (**"U.S. GAAP"**). The financial information for the six month periods ended 30 June 2017 and 2018 are unaudited. For full details of the basis of preparation and significant accounting policies, please refer to Note 2 (*Significant Accounting Policies*) to the Group's consolidated financial statements for the year ended 31 December 2016 and Note 2 (*Significant Accounting Policies*) to the Group's consolidated financial statements for the year ended 31 December 2017, as set out in Appendix 1 (*Historical Financial Information*).

As explained in Note 2 (*Significant Accounting Policies*) to the Group's condensed consolidated financial statements for the six months ended 30 June 2018, the Company adopted Accounting Standard Codification (**"ASC"**) 606 Revenue from Contracts with Customers with a date of initial application of 1 January 2018 in accordance with the modified retrospective approach without using the practical expedients. Except for providing enhanced disclosures about the Company's revenue transactions, the application of ASC 606 did not have an impact on the Company's consolidated financial position, results of operations or cash flows.

Unless otherwise stated in this Prospectus, financial information in relation to the Group referred to in this Prospectus has been extracted without material adjustment from the historical financial information in Appendix 1 (*Historical Financial Information*). Unless otherwise indicated, none of the financial information relating to the Group in this Prospectus has been audited.

2.1 **Non-U.S. GAAP financial measures and other metrics**

In this Prospectus, the Group presents certain financial measures and other metrics that are not recognised under U.S. GAAP and are unaudited. The Directors believe that each of these measures provides useful information with respect to the performance of the Group's business and operations. These non-GAAP financial measures and other metrics are not measures recognised under U.S. GAAP or any other internationally accepted accounting principles, and prospective investors should not consider such measures as an alternative to the U.S. GAAP measures included in the Group's historical financial information. The non-GAAP financial measures and other metrics may not be comparable to similarly titled measures presented by other companies as there are no generally accepted principles governing the calculation of these measures and the criteria upon which these measures are based can vary from company to company. These measures include "operating netback", "EBITDA" and "funds flow from operations". Please see paragraph 2.2 of Part IV (*Operating and Financial Review*) for further information.

Even though the non-GAAP financial measures and other metrics are used by management to assess the Group's financial results and these types of measures are commonly used by investors, they have important limitations as analytical tools, and investors should not consider them in isolation or as substitutes for analysis of Group's position or results as reported under U.S. GAAP.

Unaudited financial measures and other metrics in relation to Group have been derived from (i) management accounts for the relevant accounting periods presented; (ii) internal financial reporting systems supporting the preparation of the Group's historical financial information contained in Appendix 1 (*Historical Financial Information*); and (iii) the Group's other business operating systems and records. Management accounts are prepared using information derived from accounting records used in the preparation of the Group's historical financial information contained in Appendix 1 (*Historical Financial Information*), but may also include certain other assumptions and analyses.

3. **Oil and Gas Data**

Unless expressly stated otherwise, all estimates of proved, probable and possible reserves and related future net revenue and prospective resources disclosed in this Prospectus have been prepared in accordance with Canadian National Instrument 51-101 – Standards for Oil and Gas Activities (**"NI 51-101"**). Unless otherwise noted, reserves estimates are presented on a "company gross" basis, representing the Group's working interest share before deduction of royalties.

BOEs have been converted on the basis of six thousand cubic feet (**"Mcf"**) natural gas to 1 barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, given that the value ratio based on the current price of oil as compared with natural gas is significantly different from the energy equivalent of six to one, utilising a BOE conversion ratio of 6 Mcf: 1 bbl would be misleading as an indication of value.

4. **MARKET, ECONOMIC AND INDUSTRY DATA**

This Prospectus includes certain market, economic and industry data, which were obtained by the Company from industry publications, data and reports compiled by professional organisations and analysts, data from other external sources. The market, economic and industry data set out in this Prospectus that has been sourced from third parties has been accurately reproduced and, so far as the Company is aware and is able to ascertain from information published by such third parties, no facts have been omitted which would render the reproduced information inaccurate or misleading. Where third-party information has been used in this Prospectus, the source of such information has been identified.

Some of the aforementioned third-party sources may state that the information they contain has been obtained from sources believed to be reliable. However, such third party sources may also state that the accuracy and completeness of such information is not guaranteed and that the projections they contain are based on significant assumptions. As the Company does not have access to the facts and assumptions underlying such market date, statistical information and economic indicators contained in these third party sources, the Company is unable to verify such information.

Statements regarding the oil and gas industry which are not based on published statistical data or information obtained from independent third parties, are based on the Group's and/or the Directors' experience, the Group's internal studies and estimates, and the Group's own investigation of market conditions. The Company cannot assure prospective investors that any of these studies or estimates are accurate, and none of the Group's internal surveys or information has been verified by any independent sources. While the Directors are not aware of any misstatements regarding the Group's own estimates presented herein, those estimates involve risks, assumptions and uncertainties and are subject to change based on various factors, including those set out in the section of this Prospectus entitled "*Risk Factors*".

5. ROUNDING

Some historical financial information, percentages and other amounts included in this Prospectus have been rounded for ease of presentation. As a result of this rounding, figures shown as totals of rows or columns in certain tables in this Prospectus may vary slightly from the exact arithmetic aggregation of the figures that precede them. In addition, certain percentages presented in this Prospectus reflect calculations based upon the underlying information prior to rounding and, accordingly, may not conform exactly to the percentages that would be derived if the relevant calculations were based upon the rounded numbers.

6. CURRENCY PRESENTATION

Unless otherwise indicated, all references in this Prospectus to **"USD"**, **"U.S. dollars"**, **"$"**, **"cents"** or **"c"** are to the lawful currency of the United States and all references in this Prospectus to **"£"** or **"pounds sterling"** are to the lawful currency of the United Kingdom;

Unless otherwise indicated, the historical financial information contained in this Prospectus has been expressed in U.S. dollars. The Company's functional currency is U.S. dollars and the Company presents its financial statements in U.S. dollars.

7. FORWARD-LOOKING STATEMENTS

This Prospectus contains statements that are, or may be deemed to be, forward-looking statements. These forward-looking statements can be identified by the use of forward-looking terminology, including the terms "anticipates", "believes", "estimates", "expects", "intends", "may", "plans", "projects, "should" or "will" or, in each case, their negative or other variations or similar terminology. These forward looking statements include all matters that are not historical facts. They appear in a number of places throughout this Prospectus and include, but are not limited to, statements regarding the Directors' intentions, beliefs or current expectations concerning, among other things, the Group's results of operations, financial position, prospects, growth and strategies, and the development of the industry in which the Group operates.

By their nature, such forward-looking statements involve unknown risks, uncertainties and other factors because they relate to events and depend on circumstances that may or may not occur in the future. Forward-looking statements are not guarantees of future performance and the Group's actual results of operations, financial condition, prospects, growth and strategies, and the development of the industry in which the Group operates, may differ materially from those expressed or implied by the forward-looking statements set out in this Prospectus. In addition, even if the Group's results of operations, financial condition, prospects, growth and strategies, and the development of the markets and the industry in which the Group operates, are consistent with the forward looking statements contained in this Prospectus, those results or developments may not be indicative of results or developments in subsequent periods.

Important factors that could cause the Group's results and developments to differ materially from those expressed or implied by the forward looking statements include, but are not limited to:

- decreases in the prices of oil and gas or sustained low prices;
- difficulty in predicting the results of oil and natural gas exploration and controlling the costs of a drilling program;
- potential challenges in future oil and gas exploration, not only from difficulties in finding and developing additional oil and gas reserves, but from dry wells or wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs.
- potential challenges in obtaining, sustaining or renewing critical licences or permits and remaining compliant with complex and stringent laws and regulations;
- the complex legal, social, political and economic factors in Colombia, including potential political or economic instability;
- social disruptions, community disputes and security concerns; and
- environmental risks and potential hazards and maintaining compliance with all applicable environmental laws and regulations.

and other factors described in the section titled "*Risk Factors*".

Prospective investors are advised to read, in particular, the following parts of this Prospectus for a more complete discussion of the factors that could affect the Group's future performance and the industry in which the Group operates: the section titled "*Risk Factors*", Part I (*Information on Gran Tierra*), Part IV (*Operating and Financial Review*) and Appendix 1 (*Historical Financial Information*). In light of these factors, the events described in the forward-looking statements in this Prospectus may not occur.

The forward-looking statements contained in this Prospectus, including estimates of oil and gas reserves future net revenues therefrom, speak only as of the date of this Prospectus. Each of the Company, the Directors and RBC Capital Markets expressly disclaims any obligation or undertaking to update or revise publicly any forward-looking statements, whether as a result of new information, future events or otherwise, unless required to do so by applicable law, the Prospectus Rules, the Listing Rules, the Disclosure Guidance and Transparency Rules or MAR.

8. NO INCORPORATION OF WEBSITE

The contents of the Company's website at www.grantierra.com, the contents of any website accessible from hyperlinks on the Company's website or any other website referred to in this Prospectus are not incorporated into, and do not form part of, this Prospectus.

9. DEFINITIONS

A glossary and a list of defined terms used in this Prospectus is set out in Part IX (*Definitions*) and Part X (*Glossary of Technical Terms*).

CONSEQUENCES OF A STANDARD LISTING

Application has been made for the Common Stock to be admitted to listing on the Standard Listing Segment of the Official List pursuant to Chapter 14 of the Listing Rules, which sets out the requirements for standard listings and other continuing obligations that will be applicable to the Company. A standard listing provides investors in the Common Stock with a lower level of regulatory protection than that provided to investors in companies whose securities are admitted to the premium listing segment of the Official List, which are subject to additional obligations under the Listing Rules. While the Company has a standard listing, it is not required to comply with the provisions of, among others:

- Chapter 7 of the Listing Rules, to the extent that they refer to the Premium Listing Principles;
- Chapter 8 of the Listing Rules regarding the appointment of a listing sponsor to guide the Company in understanding and meeting its responsibilities under the Listing Rules in connection with certain matters. The Company is not required to, and does not intend to, appoint a sponsor in relation to the publication of this Prospectus or Admission;
- Chapter 9 of the Listing Rules containing provisions relating to transactions, including, *inter alia*, requirements relating to further issues of shares, the ability to issue shares at a discount in excess of 10 per cent of the market value, notifications and contents of financial information;
- Chapter 10 of the Listing Rules relating to significant transactions;
- Chapter 11 of the Listing Rules regarding related party transactions;
- Chapter 12 of the Listing Rules regarding purchases by the Company of its shares of Common Stock; and
- Chapter 13 of the Listing Rules regarding the form and content of circulars to be sent to Shareholders.

The Common Stock are and, following Admission, will continue to be listed on the NYSE American and on the TSX. Accordingly, the Company will continue to be subject to the rules of the NYSE and of the TSX.

EXPECTED TIMETABLE OF PRINCIPAL EVENTS

	Time/date
Publication of this Prospectus	28 September 2018
Admission and commencement of dealings in the Common Stock on the London Stock Exchange	8.00 a.m. on 10 October 2018

The above dates and times may be brought forward or extended and any changes will be notified via a Regulatory Information Service. References to times are to London time unless otherwise stated.

DIRECTORS, COMPANY SECRETARY AND ADVISERS

Directors	Robert B. Hodgins (*Chairman and Independent Director*) Gary S. Guidry (*Non-Independent Director, President and Chief Executive Officer*) Peter J. Dey (*Independent Director*) Evan Hazell (*Independent Director*) Ronald W. Royal (*Independent Director*) Sondra Scott (*Independent Director*) David P. Smith (*Independent Director*) Brooke Wade (*Independent Director*)
Company Secretary	Diane Phillips
Principal Place of Business	900, 520 - 3 Avenue SW Calgary, Alberta Canada T2P 0R3
Financial Adviser	RBC Europe Limited Riverbank House 2 Swan Lane London EC4R 3BF
Legal advisers to the Company as to English law	Ashurst LLP Broadwalk House 5 Appold Street London EC2A 2HA
Legal advisers to the Company as to U.S. law	Gibson, Dunn & Crutcher LLP 811 Main Street Suite 3000 Houston, TX 77002 United States
Legal advisers to the Company as to Canadian Law	Stikeman Elliott LLP 4300 Bankers Hall West 888 – 3rd Street S.W. Calgary, Alberta Canada T2P 5C5

Auditors[1]	KPMG LLP 3100-205 5th Avenue SW Calgary, Alberta Canada
	Deloitte LLP 700, 850–2nd Street SW Calgary, Alberta Canada T2P 0R8
Transfer Agent	Computershare – USA 462 South 4th Street, Suite 1600 Louisville, KY 40202 United States

[1] Deloitte LLP acted as the Group's auditor in respect of the financial years ended 31 December 2015, 2016 and 2017. The Group's auditor is currently KPMG LLP. Please see paragraph 18.2 of Part VII (*Additional Information*) for further information.

PART I – INFORMATION ON GRAN TIERRA

1. OVERVIEW

Gran Tierra is an independent international exploration and production company with onshore oil production focussed in Colombia. The Group's core assets are located in the Middle Magdalena and the Putumayo basins. The Group's Colombian properties represented 100% of its proved reserves at 31 December 2017. For the year ended 31 December 2017, 98% (year ended 31 December 2016 – 97%) of the Group's revenue and other income was generated in Colombia.

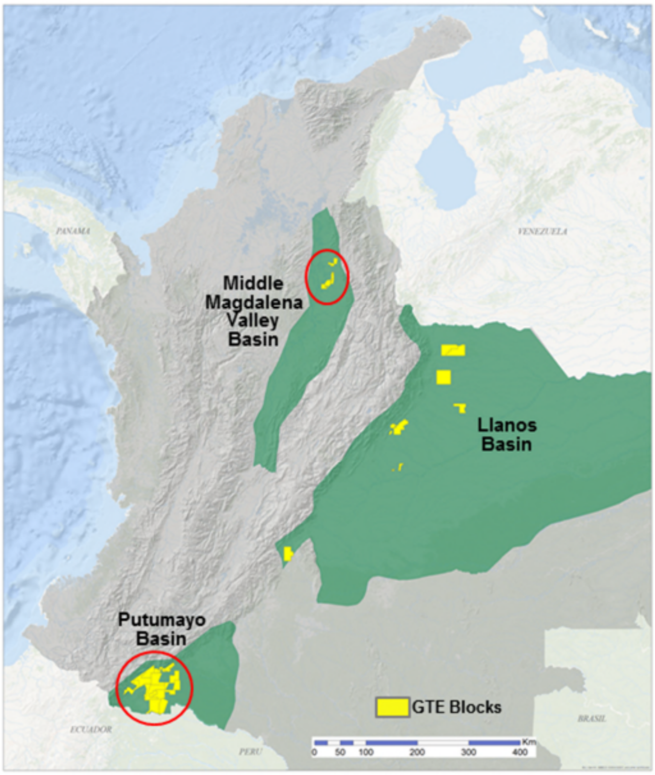
The Company believes in creating value for all of its stakeholders through oil and gas exploration and production, capitalising on the global operating experience of its team. The Common Stock is currently listed on the NYSE American and on the TSX.

2. THE GROUP'S OPERATIONS AND ASSETS

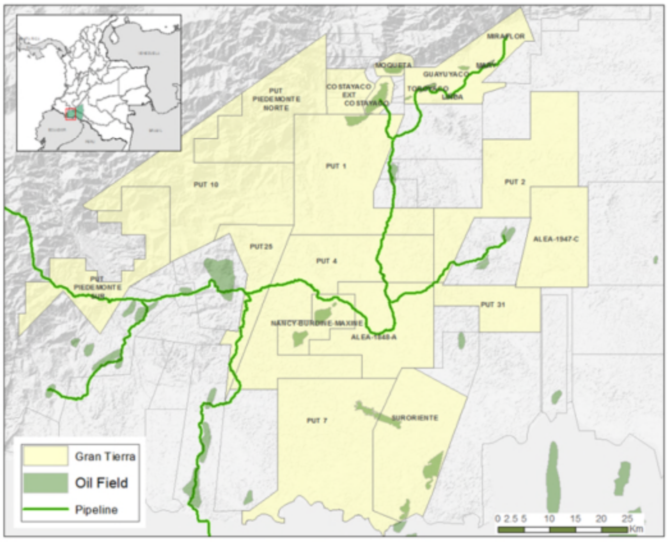
The Group's core producing assets include the Acordionero, Costayaco and Moqueta Fields in Colombia, which collectively represented 82% of the Group's production (WI) for the six months ended 30 June 2018. The Acordionero Field is located in the Middle Magdalena Valley Basin (the **"MMV Basin"**) on the Midas block (100% WI, operated), which the Group acquired in 2016 as part of the acquisition of PetroLatina Energy Limited (**"PetroLatina"**). The Acordionero Field provided production of 17,233 BOEPD (WI) for the six months ended 30 June 2018. The Acordionero Field provides near-term conventional development opportunities with significant waterflood potential. The Costayaco and Moqueta Fields are both located in the Putumayo basin on the Chaza block (100% WI, operated). The Costayaco and Moqueta Fields collectively produced 33% of the Group's production (WI) for the six months ended 30 June 2018 and have low decline rates.

The Group is also developing a new carbonate play in the Putumayo basin, the A-Limestone. The Vonu-1 discovery well, Putumayo 1 block (**"PUT-1"**) (55% WI) remains Gran Tierra's strongest A-Limestone well to date in terms of oil production performance and has already produced over 600,000 bbls of oil (100% gross cumulative) as of 30 June 2018.

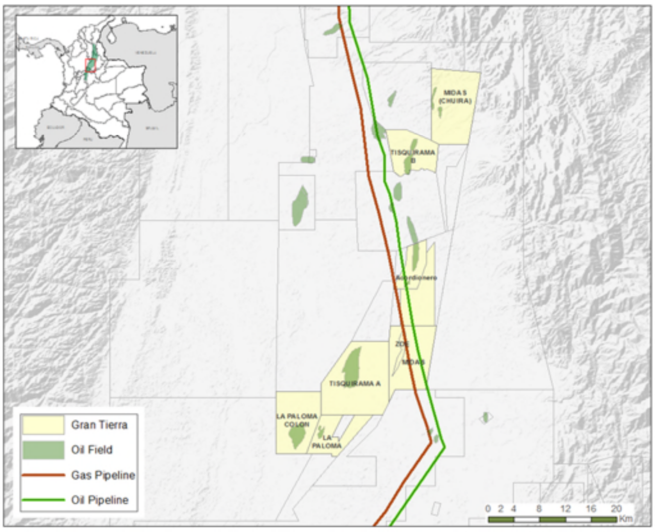
The following maps show the locations of the Group's assets.



Putumayo Basin



Middle Magdalena Valley Basin



The Company believes the Group's existing portfolio in Colombia provides significant development inventory to continue to grow its production. Following several acquisitions in 2016 and 2017, the Group has successfully consolidated sufficient exploration opportunities to commence a three to five year continuous exploration programme, which it expects will be fully funded by cash flows from the Group's Colombian operations. The exploration programme targets drilling 30 to 35 exploration wells in primarily proven basins in Colombia, including the Putumayo, the Middle Magdalena Valley and Llanos basins.

For the remainder of 2018, the Group's exploration programme is focused mainly on the Putumayo basin. Gran Tierra plans to drill the Pomorroso, Pecari and Northwest multi-zone exploration prospects in sequence from the same drilling pad at PUT-7. These three exploration wells are planned to target the A-Limestone and the U and N Sands. Gran Tierra also plans to drill Chilanguita-1 on the Alea 1848A block (100% WI) to target the A-Limestone, M2-Limestone, U and T Sands and the Caballos Formation. Drilling is also under way on the Juglar Deep exploration well in the Middle Magdalena Valley.

The Group is primarily focussed on its existing portfolio of assets in Colombia and intends to pursue new growth opportunities, leveraging on its technical expertise and financial strength.

Excluding blocks subject to relinquishment, the Group has interests in 30 blocks in Colombia and is the operator on 26 of these blocks.

2.1 Producing Assets

The following table provides a summary of the Group's position in blocks with current production.

Basin	Block	Producing Fields	Operated	Working Interest	Partners	Gross Acres	End of Exploitation Phase[1]
Putumayo	Chaza	Costayaco, Moqueta, Guriyaco	Yes	100%	N/A	16,472	2033 (Costayaco & Guriyaco) 2037 (Moqueta)
Putumayo	Guayuyaco	Guayuyaco, Juanambu	Yes	70%	Ecopetrol	52,366	2030
Putumayo	NBM	Nancy	Yes	100%	N/A	26,187	Until economic limit
Putumayo	PUT-1	Vonu	Yes	55%	Lewis Energy	114,881	24 years from commerciality
Putumayo	PUT-7	Cumplidor, Confianza	Yes	100%	N/A	130,186	24 years from commerciality
Putumayo	Santana	Mary, Miraflor, Toroyaco	Yes	100%	N/A	1,119	Until economic limit
Putumayo	Suroriente	Cohembi, Quinde	No	15.8%	Vetra, Ecopetrol	90,264	2024
Llanos	Garibay	Jilguero	No	30-50%	Cepsa	1,903	2037
Llanos	LLA-22	Ramiriqui	No	45%	Cepsa	25,018	2038
MMV	La Paloma	Colon, Juglar	Yes	100%	N/A	23,756	2034 (Colon) 2039 (Juglar)
MMV	Midas	Acordionero, Chuira, Zoe	Yes	100%	N/A	26,108	2039 (Acordionero) 2035 (Chuira) 2036 (Zoe)
MMV	Tisquirama B	Los Angeles, Querubin	Yes	20-40%	Ecopetrol	10,719	Until economic limit
MMV	VMM-2	Mono Arana	Yes	60%	Canacol	4,200	2039

Note:

(1) End of exploitation phase means the date at which the owner ceases to have the right, under the relevant E&P contract, to produce hydrocarbons from that exploitation area, although the owner may request an extension of the exploitation phase until the economic limit of the field or fields contained in such exploitation area (which may or may not be granted by the regulator).

(a) *Acordionero Field*

The Acordionero Field is located within the MMV Basin, which is one of the main oil and gas producing basins in Colombia, accounting for approximately 15% of current oil and gas production in the country. The MMV Basin is located along the central part the Magdalena river valley between the Eastern and Central Cordilleras of the Colombian Andes. The eastern and western basin boundaries are related to blocks of pre-Cretaceous rocks of Cordilleras and is bounded to the north and south by major fault systems. The basin is only approximately 80 kilometres wide but extends from south to north by approximately 450 kilometres.

The MMV Basin sedimentary fill consists of Jurassic-Lower Cretaceous (Berriasian) fluvial clastic and volcanic rocks, Lower Cretaceous calcareous and silica-clastic shallow marine depositions, Albian-Maastrichtian shallow to deep marine strata (Simiti and La Luna formations) and Upper Cretaceous – Paleocene shallow marine to non-marine siliciclastic rocks (Umir and Lisama formations). The upper section consists of Cenozoic fluvial and lacustrine rocks deposited during the growing Eastern and Central Cordilleras.

The Acordionero Field is part of the Midas block located in western-central Colombia. The Acordionero Field was discovered in 2013 with the drilling of the ACD-1 well. Since that time two wells were drilled in 2014, one in 2015 and two in 2016. In addition, in 2017 Gran Tierra drilled 12 production wells and two water injection wells in the field. Production commenced in July 2013 and the cumulative production from the field was 8.3 MMbbl as of 31 December 2017 and cumulative production as of 31 July 2018 was 12.2 MMbbl.

The two main oil-bearing reservoirs in the field are referred to as the Lisama A Sand and Lisama C Sand. A smaller oil accumulation also exists in the Lisama D Sand and Gran Tierra is also currently exploring deeper intervals below the Lisama D Sand.

In 2017, Gran Tierra received regulatory approval for a water flood project in the Acordionero Field, and its 15,000 bwpd injection facility was brought on line. The Company has successfully injected water in the Lisama A and C in both the ACD-8i and ACD-14i injector wells. Going forward, Gran Tierra plans to drill an additional 12 development wells and four injection wells in the field and is expanding its central processing facility to increase water injection capacity up to 40,000 bwpd, fluid handling capacity up to 45,000 bfpd and truck loading capacity up to 30,000 bopd in 2018 to 2019. The crude oil produced from the Acordionero Field is delivered via truck to Puerto Bahia.

Key parameters of the field are summarised below.

	1P	**2P**	**3P**
Reserves (MMBOE)	33.2	72.0	105.7
NPV10 BT (US$MM)	855.5	1,625.2	2,251.1
Future Development Locations	7	9	12
Future Development Costs (US$MM)	103.0	131.8	147.4
Economic Limit	2028	2038	2042

(b) *Costayaco Field*

The Costayaco Field is located in the northern part of the Putumayo basin, which itself is the northernmost part of a large foreland Putumayo-Oriente-Marañon basin straddled from Colombia through Ecuador to Peru. The names of the individual parts of the whole geological basin change based on the political borders and as such the Putumayo basin refers only to the part situated in Colombia.

From the west and northwest, the Putumayo basin is bounded by the Eastern Cordillera foothills thrust belt and the Garzon Massif. Through the adjacent Caguan basin, the Putumayo basin is separated to the north from the Llanos basin by the Macarena Uplift and limited to the east by the Guyana Shield. Towards the south, the Putumayo basin becomes the Oriente basin without any identified geological boundary.

The Chaza block covers approximately 189 square kilometres which also includes the Guriyaco and Moqueta fields. The Costayaco Field was discovered in 2007 with the drilling of the C-1 well. As of 31 December 2017, 30 wells had been drilled in the Costayaco Field; the first in 2007, 25 from 2008 to 2015, two in 2016 and two in 2017.

There are five productive zones. The major reservoirs are the Caballos and T Sand of the Villeta Formation, the emerging reservoir is the A-Limestone and the secondary targets are the U Sand and Kg Sand.

Production commenced in July 2007 and the cumulative production from the field was 51.3 MMbbl as of 31 December 2017 and 53 MMbbl as of 31 July 2018. Gran Tierra is planning to drill seven new wells in the Costayaco Field between 2018 and 2019, five of which are targeting the A Limestone.

Key parameters of the field are summarised below.

	1P	**2P**	**3P**
Reserves (MMBOE)	13.7	21.0	31.6
NPV10 BT (US$MM)	252.1	376.3	516.2
Future Development Locations	6	9	12
Future Development Costs (US$MM)	49.2	79.0	99.9
Economic Limit	2025	2028	2041

(c) *Moqueta Field*

The Moqueta Field is located in the north-western part of the Putumayo basin immediately north of the Costayaco Field. Unlike the Costayaco Field, the Moqueta Field is fully situated in the Andean foothills zone dominated by thrust tectonics. The Urcusique Fault bounds the Moqueta Field to the north and defines the edge of the Andes Mountains in the area. The structure is bounded in other directions by high angle reverse faults.

Gran Tierra entered the Chaza block in 2006 and the Moqueta Field was discovered in 2010 with the drilling of the M-1 well. Gran Tierra is the operator of the Chaza block and holds a 100% working interest.

22 wells have been drilled in the Moqueta Field to date; the first three in 2010, 16 in 2011 to 2015 and three in 2016. This does not include sidetracks, lost boreholes or wells that ultimately penetrated other thrust sheets.

A majority of the wells drilled targeted the Caballos and T Sand with the U Sand as a secondary target, although all production is from the Caballos and T Sand.

The Moqueta Field is interpreted to have two main separate fault blocks referred to as the West and East blocks. The West block is further divided into North and South regions. The West block commenced commercial production in late 2011, and as of October 2017 was producing approximately 4,000 bopd with a 50% water-cut. A water injection project was implemented in the West block in February 2013. As of 31 December 2017, the current water injection rates are approximately 8,800 bwpd.

The East block also commenced production in late 2011 and as of October 2017 was producing approximately 580 bopd with a 28% water-cut. A water injection project was implemented in the East block in early 2016 and water injection rates were approximately 1,600 bwpd at 31 December 2017. Water injection rates as of 31 July 2018 are approximately 1,700 bwpd.

Key parameters of the field are summarised below.

	1P	2P	3P
Reserves (MMBOE)	7.1	9.9	14.8
NPV10 BT (US$MM)	101.8	144.8	209.5
Future Development Locations	2	2	2
Future Development Costs (US$MM)	17.3	17.3	17.3
Economic Limit	2028	2031	2037

2.2 Exploration Assets

The following table provides a summary of the Group's position in exploration blocks.

Basin	Block	Operated	Working Interest	Partners	Gross Acres	Remaining Commitments, Current Phase	End of Current Phase(1)
Putumayo	Alea 1848-A	Yes	100%	N/A	75,764	70 km 2D seismic, 1 exploration well	2018
Putumayo	Alea 1947-C	Yes	100%	N/A	58,068	1 exploration well	Suspended(2)
Putumayo	PPN	Yes	70%	Cepsa	78,742	52 km 2D seismic	Suspended(2)
Putumayo	PPS	Yes	100%	N/A	73,898	2 km 2D seismic, 1 exploration well	Suspended(2)
Putumayo	PUT-1	Yes	55%	Lewis Energy	114,881	2 exploration wells	2020
Putumayo	PUT-2	Yes	100%	N/A	96,666	3 exploration wells	2019
Putumayo	PUT-4	Yes	100%	N/A	126,848	1 exploration well	2019
Putumayo	PUT-7	Yes	100%	N/A	130,186	1 exploration well	2018
Putumayo	PUT-10	Yes	100%	N/A	114,097	73 km 2D seismic, 2 exploration wells	Suspended(2)
Putumayo	PUT-25	Yes	100%	N/A	41,015	N/A	2018
Putumayo	PUT-31	Yes	100%	N/A	34,826	N/A	2018
Llanos	El Porton	Yes	100%	N/A	109,476	1 exploration well	Suspended(2)
Llanos	LLA-1	Yes	100%	N/A	133,954	97.5 km^2 3D seismic, 1 exploration well	Suspended(2)

Basin	Block	Operated	Working Interest	Partners	Gross Acres	Remaining Commitments, Current Phase	End of Current Phase(1)
Llanos	LLA-10	No	50%	Parex	189,536	1 exploration well	Suspended(2)
Llanos	LLA-22	No	45%	Cepsa	25,018	85 km^2 3D seismic, 1 exploration well	Suspended(2)
Llanos	LLA-53	Yes	100%	N/A	67,456	89 km^2 3D seismic, 2 exploration wells (approval requested to transfer commitments to PUT4- and PUT-7)	Suspended(2)
Llanos	LLA-70	Yes	100%	N/A	109,519	163 km^2 3D seismic, 1 exploration well	Suspended(2)
Caguan-Putumayo	Tinigua	Yes	40%	Frontera	105,466	1 exploration well	Suspended(2)
Sinú	SN-1	Yes	60%	Perenco	503,000	1 stratigraphic well (pending approval to convert to exploration well)	2018
Sinú	SN-3	Yes	51%	Pluspetrol	483,000	N/A	2018

Notes:

(1) Dates are subject to extension based on progress of activities and other factors, such as delays in local consultations.

(2) Gran Tierra's obligation to carry out the exploration activities on these blocks is currently suspended indefinitely due to licensing restrictions or security issues.

3. SUMMARY OF RESERVES

The following table summarises Gran Tierra's NI 51-101 and COGEH compliant WI reserves and NPV discounted at 10% before tax as provided for in the report of Gran Tierra's reserves with an effective date of 31 July 2018 (the **"Competent Person's Report"**), as prepared in accordance with NI 51-101 and COGEH by McDaniel & Associates Consultants Ltd. and calculated using McDaniel's commodity price forecasts at 1 July 2018. The Competent Person's Report is set out in full in Appendix 2 (*Competent Person's Report*) of this Prospectus.

	Light and Medium Crude Oil	Heavy Crude Oil	Conventional Natural Gas	31 July 2018	NPV 10% Discount Before Tax
Reserves Category	*Mbbl*	*Mbbl*	*MMcf*	*MBOE*	*$million*
Proved Developed Producing	29,182	13,969	1,474	43,397	1,059
Proved Developed Non-Producing	5,545	51	0	5,596	105
Proved Undeveloped	8,185	12,987	792	21,304	319

	Light and Medium Crude Oil	Heavy Crude Oil	Conventional Natural Gas	31 July 2018	NPV 10% Discount Before Tax
Total Proved	42,912	27,008	2,266	70,297	1,483
Total Probable	28,687	37,914	1,303	66,819	1,238
Total Proved plus Probable	71,600	64,922	3,569	137,116	2,721
Total Possible	41,140	31,337	1,656	72,753	1,199
Total Proved plus Probable plus Possible	112,740	96,258	5,225	209,869	3,920.

Estimates of net present value contained herein do not necessarily represent fair market value of reserves. Estimates of reserves and future net revenue for individual properties may not reflect the same level of confidence as estimates of reserves and future net revenue for all properties, due to the effect of aggregation.

4. RECENT DEVELOPMENTS AND TRENDS

Prices and markets for oil and natural gas are unpredictable and tend to fluctuate significantly, which could impact the oil and gas industry and Gran Tierra's profitability and growth. Revenues are derived from the sale of oil, which price is based on world demand, supply, weather, geopolitical unrest, and other factors, all of which are beyond its control.

The oil and gas industry is highly competitive. Gran Tierra faces competition from both local and international companies, which impacts its ability to acquire properties, contract for drilling and other oil field equipment and secure trained personnel.

Activity in the Colombian oil and gas sector remains steady. As in other countries, drilling and other activities have increased with recent improvements in oil prices. A number of international companies remain active in the country, including in exploration and production, marketing and transportation, oilfield services and other aspects of the industry.

5. KEY STRENGTHS

The Directors believe the Group benefits from the following competitive strengths:

5.1 High quality reserves and resources

The Group's asset base includes a diverse portfolio of oil-weighted producing assets and significant reserves that span multiple proven basins in Colombia. For the six months ended 30 June 2018, the Group's production (WI) was 35,239 BOEPD, and for the year ended 31 December 2017, the Group's production (WI) was 31,426 BOEPD, which was approximately 100% oil in each period. The Group's assets are characterised by high operating netbacks, an attractive cost structure and low decline rates, which drive the generation of meaningful free cash flow. The Group's significant land base spans multiple basins in Colombia and totals over 2.1 million net acres, much of which is undeveloped and prospective for significant resources.

Gran Tierra produces mainly light oil (approximately 29° API) at the Costayaco and Moqueta fields and heavy oil (approximately 19° API) at the Acordionero Field. The Group's main fields have low declines, with five-year forward-looking 1P decline rates of approximately 14% at Acordionero, 17% at Costayaco and 12% at Moqueta, as provided for in the report of Gran Tierra's reserves with an effective date of 31 December 2017 (the **"McDaniel NI 51-101 Reserve Report"**), as prepared in accordance with NI 51-101 and COGEH by McDaniel & Associates Consultants Ltd. and calculated using McDaniel's commodity price forecasts at 31 December 2017. Further information on the McDaniel NI 51-101 Reserve Report is available in Gran Tierra's Statement of Reserves Data and

Other Oil and Gas Information (Form 51-101 F1), which is available on SEDAR at www.sedar.com under the Company's profile.

The largest portion of the Group's development activity is at Acordionero, which is highly economic, with an internal rate of return (**"IRR"**) of 394% based on 6 November 2017 Brent strip pricing.

5.2 Significant drilling inventory and resource potential

The Group's portfolio includes a large and highly prospective land position in proven hydrocarbon basins, consisting of blocks with multiple drilling leads and prospects in different geological formations, providing attractive opportunities with varying levels of risk. The Group's development plans and drilling inventory target locations that provide strong economics and support a predictable production profile, as demonstrated by recent successful well results at the Acordionero asset in the MMV Basin and successful exploration well results in the A-Limestone and N Sand plays in the Putumayo basin. Additionally, in the Putumayo basin the Group holds a dominant land position, has an extensive seismic database (16,807 kilometres of 2D seismic and 1,716 km^2 of 3D seismic) and controls significant infrastructure in the area, which enhances its ability to develop potentially large carbonate resource plays (including the A-Limestone) and explore multi-zone targets throughout the basin.

The Group's geoscience team continues to identify new potential oil and gas accumulations, thereby expanding its inventory of prospects and drilling opportunities. Additionally, the Group has been actively progressing with its multiyear exploration program, which is targeting the most prospective opportunities, which include the A-Limestone and other carbonate plays, as well as the N Sand formation.

5.3 Low costs and high operating netbacks

The Group has a strong focus on controlling and reducing operating costs. These low costs generate a high operating netback relative to most of the Group's peers. The Group's F&D costs on its Colombian portfolio are also very competitive. Gran Tierra believes that $8.00 to $10.00 per BOE is sustainable in the long term, supported by the Group's 5-year average F&D costs of $8.32 per BOE (WI) and 2017 average F&D costs of $11.26 per BOE.

Gran Tierra believes the Group's low costs to find, develop and produce oil create a sustainable, full-cycle oil business that is competitive throughout commodity price cycles. The Group regularly seeks new initiatives to reduce costs and enhance operational efficiencies. For example, the Group has installed new gas-to-power facilities at the Costayaco and Moqueta fields, which have brought total power generation capabilities in these two fields up to approximately 13 megawatts. The gas-to-power projects are expected to reduce the Group's costs and eliminate the Group's dependence on the local electrical grid.

5.4 Control over operations and flexible operating structure

Over 90% of the Group's production is from assets which it operates (26 out of the 30 blocks in which it has an interest), and the Group has a high degree of operatorship in its exploration assets. This provides Gran Tierra with significant control over the pace of development. Operational control allows Gran Tierra to increase or decrease capital expenditures largely at the Group's discretion, giving it significant flexibility to adjust its capital program in the event of changes in oil prices or other external factors that may impact, positively or negatively, the Group's cash flows.

5.5 Strong financial position

Gran Tierra benefits from strong cash flow from operating activities. For the six months ended 30 June 2018, cash provided by operating activities was $130.9 million, representing an increase of 94% over the comparable period in 2017. The Group's cash flow from operating activities plays a significant role in funding its capital expenditures. The Group will also use cash flow to service its debts.

Furthermore, the Group maintains significant liquidity through $126 million of cash on hand as of 30 June 2018, as well as its committed Revolving Credit Facility of $300 million, which was undrawn as of 30 June 2018. This financial flexibility allows the Company to undertake further development on an opportunistic basis while maintaining its conservative financial policies. All financial decisions are made with the intention of remaining compliant with targeted leverage and liquidity metrics and restrictions under the Revolving Credit Facility and Senior Notes. At this time, Gran Tierra does not pay a dividend on its outstanding common stock and does not anticipate paying a dividend for the foreseeable future. Please see paragraph 13 of this Part I (*Information on Gran Tierra*) for further information relating to the Group's dividend policy.

5.6 **Successful track record of profitable growth, both organic and inorganic**

The Group's Colombian production (WI) has grown 57% since the second quarter of 2015, driven by the successful integration of the PetroLatina acquisition and growth from both the new and existing assets. Since 2015, the successful completion of four material acquisitions for a total of $689.6 million has consolidated the Group's position in the Putumayo basin and diversified Gran Tierra's core operations into the MMV Basin, which has resulted in a material increase in production and inventory of profitable exploration and development opportunities. The Group successfully achieved these results as demonstrated by its dominant land position in the Putumayo basin, diversified production and reserves from the Group's core assets and current multi-year exploration and development program. Additionally, the Group's team has demonstrated its ability to successfully integrate and operate assets, as evidenced by growth in production from the Acordionero Field from 4,730 BOEPD (WI) at the time of purchase in August 2016 to a current rate (second quarter of 2018) of 17,710 BOEPD (WI), an increase of 274%.

The Group focuses on growing production profitably, and it has achieved significant increases in production from the Acordionero Field while generating positive free cash flow. The MMV Basin has generated $327 million of oil and gas sales and $252 million of operating netback between the Group's acquisition in August 2016 and 30 June 2018, with capital investment of only $164 million. The Costayaco and Moqueta fields are largely developed and require limited capital expenditures in the future, generating free cash flows to invest in other projects.

Gran Tierra will continue to evaluate opportunities to expand its portfolio through acquisitions or other strategic transactions, especially when these assets have synergies with the Group's existing asset base, such as geographic proximity, and when these assets come with limited financial requirements in both acquisition costs and long-term capital commitments. Gran Tierra believes that it may have such opportunities in the near term.

5.7 **Access to transportation infrastructure and focus on costs and realised prices**

There are numerous options for transportation of the Group's crude oil within Colombia, and the Group's marketing team works to continuously increase operating netbacks by securing transportation capacity on multiple routes, managing costs and seeking out the best sales prices. Spare capacity exists on many pipelines in Colombia, and the country has an active trucking industry with competitive costs. These ensure reliability of sales and allow monetisation of new oil discoveries relatively quickly.

The Group's Putumayo crude is currently sold mainly via the Oleoducto de Crudos Pesados (**"OCP"**) pipeline and the Oleoducto Transandino (**"OTA"**) pipeline. It may also be sold at the port of Coveñas via truck or a combination of truck and pipeline. The Group's Acordionero crude is currently sold at ports on Colombia's Caribbean coast via truck or a combination of truck and barge. A large portion of the Group's crude sales take place at or near the wellhead, with transportation costs deducted from the sales price. Transportation costs (including those deducted from the sale price as well as direct transportation costs) and quality differentials generally result in a total discount of approximately $12-14 per barrel for Gran Tierra's production. The Group's marketing team manages location and quality differentials and transportation costs on an integrated basis with the goal of achieving the highest wellhead price.

5.8 **Experienced management team with strong knowledge of the oil and gas industry**

Gran Tierra has assembled a highly qualified management team with significant experience operating international oil and gas companies. The Group's senior management team has on average more than 25 years of experience in the international oil and gas industry, extensive experience operating in Latin America, and in the exploration, production, marketing and management of oil and gas companies through different economic cycles. Prior to joining Gran Tierra in 2015, much of Gran Tierra's management team worked together at multiple previous successful ventures, including Caracal Energy, Orion Oil & Gas, and Tanganyika Oil Company. Each of these ventures resulted in the creation of significant value for shareholders.

6. STRATEGY

The Group's strategy is to efficiently grow and diversify its portfolio of exploration, development and production opportunities primarily in Colombia. The Group is taking steps to grow cash flows from existing assets by developing reserves and growing reserves through enhanced oil recovery techniques.

6.1 Efficiently operate the Group's existing high quality asset base with a focus on profitability and sustainability

As part of the repositioning of Gran Tierra, which began in 2015 after the installation of its new management team, the Group changed its core focus to Colombia and the cost structure of its organisation. Gran Tierra's goal was to create a sustainable business model by focusing on full-cycle returns and maintaining the Group's financial strength. To achieve this, the Group continues to place a heavy emphasis on the profitability of its assets while maximising their ultimate recovery.

As a result, the Group's current asset base is characterised by high operating netbacks and low decline rates, which the Group strives to maintain.

At the Group's currently producing assets, the Group's focus is to maximise the ultimate recovery as efficiently as possible. At Costayaco and Moqueta, the Group has been employing waterfloods to minimise declines and enhance recovery. The Group plans to continue optimising the waterfloods (e.g. additional pumps and injectors) and maximise the wells' lifting capacity with the intention of applying best practices throughout the Group's portfolio. At the Acordionero Field, the Group continues to drill new wells, with a full 2P development plan of 28 producing wells and six injection wells (one rig expected to run continuously through 2018). The Group is also conducting a waterflood injection pilot that commenced in the fourth quarter of 2017. A successful waterflood pilot at the Acordionero Field could have a material impact on the recovery factor assumed for this field's reserves. The current recovery factors provided in the Competent Person's Report, are (1P/2P/3P) 13.7%/26%/32.5% for the Lisama-A and 24.9%/29%/35% for the Lisama-C.

Gran Tierra believes this focus on optimisation of its existing operations will maximise near-term value and allow the Group to more effectively pursue opportunities within its portfolio of assets and elsewhere.

6.2 Grow the Group's portfolio of development and exploration opportunities by capitalising on its technical expertise

The Group's strategy in building the existing portfolio is the result of a focus on proven basins, short cycle times, stable regulatory environments, access to infrastructure and sanctity of contract. The Group continues to focus on these values as it grows the portfolio with Colombia as its core geography. The Group intends to fund its growth program through internally generated cash flows.

The Group's existing asset base provides significant potential for exploration and future development opportunities. The Acordionero Field in the MMV Basin has a significant inventory of de-risked conventional drilling locations. The Group's large land position in the Putumayo basin of more than 1.1 million gross acres provides exposure to the regionally pervasive A-Limestone and N Sand oil plays.

Following the consolidation of a deep portfolio of exploration opportunities, the Group commenced a three to five year continuous exploration program that it expects will be fully funded through the reinvestment of cash flows from operations and leveraging the Group's financial strength. The Group's goals are to drill 30 to 35 exploration wells in the next three years and to test 80% of the Group's prospective resources.

The new A-Limestone and N Sand plays in the Putumayo basin were primary targets of the Group's exploration program in 2016 and 2017. Over the last two years, the Group has drilled and recompleted multiple wells in the Putumayo basin, which have resulted in multiple discoveries and the Group has identified significant potential oil resources in certain areas. The A-Limestone stratigraphic play has proven to be a regionally pervasive carbonate platform that has yielded multiple producing wells through both recompletions of existing wells (Costayaco-2, -9 and -19) and drilling of new wells

(Costayaco-28 and -29; Vonu-1; and Confianza-1). The N Sand play has been discovered and produced at Cumplidor-1, Alpha-1, Confianza-1, and Costayaco-1 and -18.

6.3 Continue to foster conservative financial policies and maintain a strong financial position

The Group seeks to maintain a prudent and sustainable capital structure and a strong financial position to allow it to maximise the development of the Group's assets and capitalise on business opportunities as they arise. The Group intends to remain financially disciplined by limiting its debt incurrence to amounts that it believes can be repaid using cash flows from existing production or low-risk, near-term development.

Gran Tierra targets a defined set of financial guidelines, including a net debt/EBITDA ratio of less than 2.0x, an EBITDA/interest expense ratio of greater than 5.0x, and a net debt to capitalisation ratio of less than 0.4x. The Group's investments generally target a minimum IRR of 20% after tax. At this time, Gran Tierra does not pay a dividend and does not intend to do so in the near term. Gran Tierra will seek to ensure that any shareholder distributions (e.g. dividends or share buybacks) are executed while remaining compliant with targeted leverage and liquidity metrics and restrictions under the Group's bank facility, which limits the dollar amount of distributions and requires certain leverage and liquidity covenants to be met.

The Group's cash flow generation is complemented by its financial hedging programme. During 2016 and 2017, it entered into derivative financial instruments to manage its exposure to oil price and foreign currency risk. The purpose of this hedging strategy is to manage the variability in cash flows associated with fluctuations in oil prices and the Group's forecasted Colombian peso (**"COP"**) denominated expenses, which represent its largest market risks.

Establishing hedges allows the Group to protect a portion of its cash flows and have greater confidence in its ability to fund its capital program for the following 12 to 18 months.

The Group believes that by maintaining a disciplined capital structure and conservative financial philosophy, including limiting the Group's debt incurrence to amounts that it believes can be repaid using cash flows from existing production or low-risk, near-term development and the Group's use of financial hedges, it is positioned to maintain sufficient liquidity and remain flexible in volatile commodity price environments. The Group's financial flexibility also gives it the ability to pursue new opportunities through future potential acquisitions.

7. MARKETING AND MAJOR CUSTOMERS

The Group's oil reserves and production in Colombia are mainly located in the Middle Magdalena Valley and Putumayo basins. In the MMV Basin, the Group's focus is on the Acordionero Field, where production is approximately 19° API and which represented 33% of the Group's production in 2017. Oil produced in the Chaza and Guayuyaco blocks is approximately 29° API and represented 59% of the Group's production in 2017. The Group's transportation arrangements are described above in paragraph 5.7 of this Part I (*Information on Gran Tierra*).

The Group has entered into numerous agreements to sell its production. The primary purchasers of the Group's production include international commodity trading firms and Ecopetrol, the Colombian national oil company. These agreements are typically for terms between three to twelve months and generally contain mutual termination provisions with 30 days' notice. Most contracts include weekly payments by the customers, minimising the Group's counterparty/credit risk.

The market for crude oil in Colombia is very active and Gran Tierra typically conducts highly competitive marketing processes, with multiple bidders for each crude contract. Many international commodity trading firms have a long history in Colombia and some have made significant infrastructure investments in the country.

The Group receives revenues for its Colombian oil sales in U.S. dollars, deposited in bank accounts outside of Colombia. Oil prices for sales of the Group's crude oil are defined by agreements with the purchasers of the oil and are based generally on an average price for crude oil, using 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.

8. **HISTORY**

The Company was incorporated under the laws of the State of Nevada on 6 June 2003, originally under the name "Goldstrike Inc". On 10 November 2005, the Company and Gran Tierra Energy Inc., a privately-held Alberta corporation, (**"Gran Tierra Canada"**) entered into a series of transactions with Gran Tierra Canada's stockholders, pursuant to which Gran Tierra Canada became a wholly-owned subsidiary of the Company. Following the transaction, the Company changed its name to "Gran Tierra Energy Inc." and continued operations with the management and business operations of Gran Tierra Canada. The Company remained incorporated in the State of Nevada until 31 October 2016, when the Company was converted into a Delaware corporation following approval by Shareholders of a change in the Company's state of incorporation from the State of Nevada to the State of Delaware.

Gran Tierra made its initial acquisition of oil and gas producing and non-producing properties in Argentina in September 2005. Since then, it has acquired oil and gas producing and non-producing assets in Colombia, Peru, Argentina and Brazil. Gran Tierra sold its Argentina business unit in 2014. In 2016, the Group completed acquisitions of Petroamerica Oil Corp. (**"Petroamerica"**), PetroGranada Colombia Limited (**"PGC"**) and PetroLatina, strengthening the Group's position in Colombia.

During 2017, it completed the sale of its assets in Brazil and Peru. On 30 June 2017, the Group completed the sale of its Brazil business unit for a purchase price of $35.0 million, which resulted in cash consideration of approximately $36.8 million after final closing adjustments. On 18 December 2017, Gran Tierra completed the sale of its Peru business unit. Pursuant to the divestiture, Sterling Resources Ltd., subsequently renamed PetroTal Corp. (**"PetroTal"**), acquired all of the issued and outstanding shares in Gran Tierra's indirect, wholly owned subsidiary that indirectly held all of the Group's Peruvian assets for aggregate consideration of $33.5 million, comprising approximately 187.3 million common shares of PetroTal and an estimated cash-settled working capital adjustment of $0.4 million. Additionally, in connection with the divestiture, Gran Tierra purchased $11.0 million of subscription receipts which were exchangeable for common shares of PetroTal Ltd. and subsequently exchanged them for approximately 58.9 million common shares of PetroTal. After giving effect to the divestiture, Gran Tierra directly and indirectly holds approximately 246.1 million common shares representing approximately 46% of PetroTal's issued and outstanding common shares.

9. **MARKET OVERVIEW**

The oil and gas industry is highly competitive. The Group faces competition from both local and international companies. This competition impacts the Group's ability to acquire properties, contract for drilling and other oil field equipment and secure trained personnel. Many competitors, such as Ecopetrol, Colombia's national oil company, have greater financial and technical resources. The Group's 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 the Group, which could adversely affect its competitive position. The Group's ability to acquire additional properties and to discover reserves in the future will depend on its ability to evaluate and select suitable properties and to 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 the Group competes to develop and produce those reserves cost effectively. In addition, the Group competes to monetise its oil production: for transportation capacity and infrastructure for the delivery of its products, to maintain a skilled workforce and to obtain quality services and materials.

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

9.1 **Colombia Administration**

The Group operates in Colombia through Colombian branches of the following entities: Gran Tierra Energy Colombia Ltd., Gran Tierra Colombia Inc. and Petrolifera Petroleum (Colombia) Limited. Gran Tierra Energy Colombia Ltd. and Gran Tierra Colombia Inc. are currently qualified as operators of oil and gas properties by the ANH.

In Colombia, the ANH is the administrator of the hydrocarbons in the country and therefore is responsible for regulating the Colombian oil and gas industry, including managing all exploration lands. Since 2003, Ecopetrol, the Colombian national oil company, has been a public company owned in majority by the state with the main purpose of exploring and producing hydrocarbons similar to any other oil company. In addition, Ecopetrol is a major purchaser and marketer of oil in Colombia and operates the majority of the oil transportation infrastructure in the country.

The ANH uses an exploration risk contract, or the Exploration and Production Contract, which provides full risk/reward benefits for the contractor. Under the terms of this contract, the successful operator retains the rights to all reserves, production and income from any new exploration block, subject to existing royalty and tax regulations. Each contract contains an exploration phase and a production phase. The exploration phase contains a number of exploration periods and each period has an associated work commitment. The production phase lasts a number of years (usually 24) from the declaration of a commercial hydrocarbon discovery.

When operating under a 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.

9.2 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 ANH contracts to which the Group is a party all have royalties that are based on a sliding scale described in Law 756 of 2002. This royalty works on an individual oil field basis starting with a base royalty rate of 8% for gross production of less than 5,000 bopd. The royalty increases in a linear fashion from 8% to 20% for gross production between 5,000 and 125,000 bopd and is stable 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%. In addition to the sliding scale royalty, the following blocks have additional x-factor royalties, being additional royalties agreed with ANH during the bidding process: Llanos-22, Putumayo-2, Putumayo-4 and Putumayo-7: 1%; Sinu-1 and Llanos-10: 3%; Putumayo-31: 12%; Sinu-3: 17%; Llanos-1: 31%; Llanos-53: 33%; Llanos-70: 31%; Putumayo 25: 19%; Santana: 32% and Nancy-Burdine-Maxine: 20% for existing production and sliding scale for new discoveries or incremental production duly approved by ANH.

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

An additional royalty (the **"HPR royalty"**) applies on exploration and production contracts signed under the ANH oil regulatory regime in 2004 and onwards when cumulative gross production from an exploitation area is greater than five MMbbl and reference prices exceed the trigger price defined in the contract. For exploration and production contracts awarded in the 2010, 2012 and 2014 Colombia Bid Rounds, the HPR royalty will apply once the production from the area governed by the contract, rather than any particular exploitation area designated under the contract, exceeds five MMbbl of cumulative production. At 31 December 2017, the Group's production from the Costayaco and Moqueta Exploitation Areas in the Chaza block and the Acordionero Exploitation Area in the Midas block were subject to the HPR royalty. The HPR royalty is calculated based on the established percent (S) of the part of the average monthly reference WTI price (P) that exceeds a base price (Po), divided by the average monthly reference price (P).The Guayuyaco and Suroriente blocks have the sliding scale royalty but do not have the additional royalty.

In addition to these government royalties, the Group's original interests in the Guayuyaco and Chaza blocks acquired on its entry into Colombia in 2006 are subject to a third party royalty. The additional interests in Guayuyaco and Chaza that the Group 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 royalty.

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, the Group is subject to a 10% NPI on 50% of the Group's working interest production from the Costayaco and Moqueta Fields in the Chaza block and 35% of the Group's working interest production from the Juanambu Field in the Guayuyaco block, and overriding royalties on the Group's working interest production from the Guayuyaco Field in the Guayuyaco block.

The Putumayo-7 block is also subject to a third party royalty in addition to the government royalties. 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 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.

10. ENVIRONMENTAL COMPLIANCE

The Group's activities are subject to laws and regulations governing environmental quality and pollution control in the countries where it operates. The Group's activities with respect to exploration, drilling, production and 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. Such regulations relate to 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. Licences and permits required for the Group's 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 the Group's operations. Spills and releases into the environment of petroleum products can result in remediation costs and liability for damages. The costs of remedying such conditions may be significant, and remediation obligations could adversely affect the Group's 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 the Group's operations in affected areas. In addition, indigenous groups or other local organisations could oppose the Group's operations in their communities, potentially resulting in delays which could adversely affect its operations. Governmental or judicial actions may influence the interpretation and enforcement of environmental laws and regulations and may thereby increase compliance costs. The Group does 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 the Group.

The Group has implemented a company wide web-based reporting system which allows it to track incidents and respective corrective actions and associated costs. The Group has a Corporate Health, Safety, and Environmental Management System 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. The Group has an environmental risk management program in place as well as waste management procedures. Air and water testing occur regularly and environmental contingency plans have been prepared for all sites and ground transportation of oil. The Group has a regular quarterly comprehensive reporting system, reporting to executive management as well as a committee of the Board. The Group also has a schedule of internal audits and routine checking of practices and procedures and conduct emergency response exercises.

11. EMPLOYEES

As at the Latest Practicable Date, the Group employed 328 full-time employees.

The following tables set out the Group's full-time employees by geographical location as at 31 December 2015, 2016 and 2017:

	As at 31 December		
Location	**2015**	**2016**	**2017**
Calgary	58	74	81
Colombia	193	265	243
Peru	28	26	-[1]
Brazil	22	22	-[2]
Total	301	387	324

Notes:

(1) The Group completed the sale of its Peru business unit on 18 December 2017.

(2) The Group completed the sale of its Brazil business unit on 30 June 2017.

12. FACILITIES

The Group is headquartered in Calgary, Alberta in Canada and has a number of leased office properties in Colombia. Further details of the Group's leased properties are set out in paragraph 15 of Part VII (*Additional Information*).

13. DIVIDEND POLICY

The Company has never declared or paid dividends on the shares of Common Stock. The Company intends to retain future earnings, if any, to support the development of the business and therefore does not anticipate paying cash dividends for the foreseeable future.

Payment of future dividends, if any, would be at the discretion of the Board 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 Revolving Credit Facility, the Company is limited in its ability to pay dividends to Shareholders without the approval of the lending banks.

PART II – DIRECTORS, SENIOR MANAGEMENT AND CORPORATE GOVERNANCE

1. DIRECTORS

The Directors of the Company are:

Name	Position
Robert B. Hodgins	Chairman and Independent Director
Gary S. Guidry	Non-Independent Director, President and Chief Executive Officer
Peter J. Dey	Independent Director
Evan Hazell	Independent Director
Ronald W. Royal	Independent Director
Sondra Scott	Independent Director
David P. Smith	Independent Director
Brooke Wade	Independent Director

The business address of each Director is 900, 520 - 3 Avenue SW, Calgary, Alberta, Canada T2P 0R3.

The management expertise and experience of the Directors are set out below.

Robert B. Hodgins, Chairman and Independent Director

Mr. Hodgins has been an independent businessman since November 2004. Prior thereto, Mr. Hodgins served as the Chief Financial Officer of Pengrowth Energy Trust (a TSX and NYSE-listed energy trust) from 2002 to 2004. Prior to that, Mr. Hodgins held the position of Vice President and Treasurer of Canadian Pacific Limited (a TSX and NYSE-listed diversified energy, transportation and hotels company) from 1998 to 2002 and was Chief Financial Officer of TransCanada PipeLines Limited (a TSX and NYSE-listed energy transportation company) from 1993 to 1998. He is currently a Senior Advisor (Investment Banking) at Canaccord Genuity. Mr. Hodgins received an Honours Bachelor of Arts in Business from the Richard Ivey School of Business at the University of Western Ontario and received a Chartered Accountant designation and was admitted as a member of the Institute of Chartered Accountants of Ontario in 1977 and Alberta in 1991. Mr. Hodgins is a member of the Institute of Corporate Directors.

Qualifications: Mr. Hodgins' 30-plus years in the oil and gas industry as an executive and director and his strong reputation in the Canadian business community brings valuable industry and leadership experience to the Board. As a Chartered Accountant and experienced executive in senior financial roles with several Canadian companies, Mr. Hodgins qualifies as one of Gran Tierra's Audit Committee financial experts.

Mr. Hodgins has been a director of the Company since May 2015.

Gary S. Guidry, Non-Independent Director, President and Chief Executive Officer

Mr. Guidry is a professional engineer and has more than 35 years of experience developing and maximising assets in the international oil and gas industry. Mr. Guidry has direct experience managing large, international projects, including assets in Latin America, Africa, the Middle-East and Asia. Prior to joining Gran Tierra, Mr. Guidry was the President and Chief Executive Officer of Caracal Energy, a London Stock Exchange listed oil and gas company with operations in Chad, Africa. He held that position from mid-2011 until the company was acquired by Glencore plc for $1.8 billion in mid-2014. In 2014, Mr. Guidry was awarded the Oil Council Executive of the Year award for his leadership role with Caracal. Prior to Caracal, Mr. Guidry was the President and Chief Executive Officer of Orion Oil and Gas (TSX-listed), which operated in western Canada from mid-2009 until mid-2011 when it was sold. From May 2005 until December 2008, he was the President and Chief Executive Officer of Tanganyika Oil Company (TSX listed) which operated in Syria and Egypt. Prior to Tanganyika, Mr. Guidry was Chief Executive Officer of Calpine Natural Gas Trust. Mr. Guidry is an Alberta-registered Professional Engineer and a member of the Association of Professional Engineers and Geoscientists. He received a Bachelor of Science in Petroleum Engineering from Texas A&M University in 1980.

Qualifications: Mr. Guidry, as Chief Executive Officer, is responsible for the operations, financial management and implementation of the Company's strategy. Mr. Guidry's extensive experience in the oil and gas industry and international operations developed through his experience as a senior executive at several publicly traded companies brings valuable expertise and perspective to the Board.

Mr. Guidry has been a director of the Company since May 2015.

Peter J. Dey, Independent Director

Mr. Dey has been the Chairman of Paradigm Capital Inc., an investment dealer, since November 2005. Mr. Dey was a Partner of the Toronto law firm Osler, Hoskin & Harcourt LLP, where he specialised in corporate board issues and mergers and acquisitions, from 2001 to 2005, and prior to that from 1985 to 1994 and from 1973 to 1983. From 1994 to 2001, Mr. Dey was Chairman of Morgan Stanley Canada Limited. From 1993 to 1995, Mr. Dey chaired The Toronto Stock Exchange Committee on Corporate Governance in Canada that released the December 1994 report entitled "*Where Were the Directors?*", known as the Dey Report. Mr. Dey has also served as Chairman of the Ontario Securities Commission and was Canada's representative to the Organisation for Economic Co-operation and Development (**"OECD"**) Task Force that developed the OECD Principles of Corporate Governance released in May of 1999. Mr. Dey attended Queen's University, where he earned his Bachelor of Science in 1963, and Dalhousie University, where he earned his Bachelor of Laws degree in 1966. He received his Master of Laws degree from Harvard University in 1967.

Qualifications: With more than 40 years of experience dealing with issues of corporate governance ranging from serving on public boards to private practice as a lawyer, Mr. Dey provides significant value to Gran Tierra. His experience as a former director with other public company boards provides significant value to Gran Tierra.

Mr. Dey has been a director of the Company since May 2015.

Evan Hazell, Independent Director

Mr. Hazell has been involved in the global oil and gas industry for over 30 years, initially as a petroleum engineer and then as an investment banker. From 1998 to 2011, Mr. Hazell acted as a managing director at several financial institutions including HSBC Global Investment Bank and RBC Capital Markets. At present he serves as a director of Primavera Resources Corp., Black Swan Energy and Kaisen Energy Corp. Mr. Hazell also serves as a director of a number of non-profit and community organisations including Calgary Municipal Land Corporation, Social Venture Partners Calgary, Opera America, and Pacific Opera Victoria. Mr. Hazell holds a Bachelor of Applied Science degree from Queen's University, a Master of Engineering degree from the University of Calgary, and a Master of Business Administration degree from the University of Michigan, and is licensed as a Professional Engineer in Alberta.

Qualifications: Mr. Hazell possesses specific attributes that qualify him to serve as a director, including his extensive experience in the global energy industry as well as in the financial sector. Mr. Hazell also has significant experience at non-profit organisations. His education in business and engineering provides significant value to Gran Tierra.

Mr. Hazell has been a director of the Company since June 2015.

Ronald W. Royal, Independent Director

Mr. Royal has been a private businessman since April 2007. Mr. Royal has more than 35 years of experience with Imperial Oil Ltd. and ExxonMobil's international upstream affiliates. From 2011 to 2014, he served on the board of directors of Caracal Energy Inc. and, prior to 2010, several other boards of private oil companies. Prior to retiring in 2007, Mr. Royal was President and Production

Manager of Esso Exploration and Production Chad Inc. and resided in N'Djamena, Chad from 2002 to 2007. In 2003, he was awarded the title "*Chevalier de l'Ordre National du Chad*" for his contribution to the economic development of Chad. Mr. Royal received his Bachelor of Applied Science from the University of British Columbia in 1972 and completed the Executive Development Program at Cornell University in 1986. He has been a member of the Association of Professional Engineers and Geoscientists of Alberta since 1972.

Qualifications: Mr. Royal brings to the Board over 35 years of experience in the oil and gas industry, having previously held a variety of management positions both domestically and internationally.

Mr. Royal has been a director of the Company since May 2015.

Sondra Scott, Independent Director

Ms. Scott is currently president of Verisk Maplecroft, a data analytics and risk assessment company, where she is responsible for leading its globalisation and growth effort in the political, economic, human rights and environmental risk analytics market. Before joining Verisk Maplecroft in 2015, Ms. Scott filled a number of roles at Wood Mackenzie, a global energy, chemicals, renewables, metals and mining research and consultancy company, over a 13-year period. Her most recent position was head of Global Markets where she led a team focusing on macro energy economics and risk. Previously, Ms. Scott led Wood Mackenzie's energy consultancy practice. Ms. Scott holds a Master of Science, Petroleum Engineering and Economics degree from a joint program with the University of Pennsylvania and the Institut Francais du Petrole (IFP) and received a Bachelor of Arts, Economics and Earth Sciences degree from Wesleyan University.

Qualifications: Ms. Scott has more than 25 years of experience as an energy and risk analytics business leader. She has significant leadership experience having led multi-sized global research and consultancy teams. Ms. Scott has worked in the United States, the United Kingdom, and Latin America, globalising businesses and building local practices.

Ms. Scott has been a director of the Company since September 2017.

David P. Smith, Independent Director

Mr. Smith is a corporate director with extensive experience in the investment banking, investment research and management industry. He has been the Chairman of the Board of Directors of Superior Plus Corp., a diversified energy and specialty chemicals company, since August 2014. From March 2004 to August 2015, Mr. Smith served as Chair of the Audit Committee of Superior Plus Corp. Previously, Mr. Smith was Managing Partner of Enterprise Capital Management Inc. Mr. Smith is a Chartered Financial Analyst and graduated with honors from the University of Western Ontario with a degree in Business Administration in 1981.

Qualifications: Mr. Smith brings to the Board significant financial expertise, having spent his professional career in investment banking, investment research and management. His experience as the Chairman at Superior Plus Corp. and his previous experience as a director and member of the audit committee of other public companies provide valuable perspective to the Board. Mr. Smith's education and experience qualifies him as one of Gran Tierra's Audit Committee financial experts.

Mr. Smith has been a director of the Company since May 2015.

Brooke Wade, Independent Director

Mr. Wade is the President of Wade Capital Corporation, a private investment company active in private equity, oil and gas, real estate and industrial businesses. From 1994 until 2005, Mr. Wade was the co-founder and Chairman and Chief Executive Officer of Acetex Corporation, a publicly traded chemical company specialising in acetyls, specialty polymers, and films. In July 2005, Acetex was acquired by Blackstone. Prior to founding Acetex Corporation, Mr. Wade was founding President and Chief Executive Officer of Methanex Corporation. In 1991, Ocelot Industries spun out its oil and gas assets and began a plan of growth through acquisition into what is today Methanex Corporation - the world's largest methanol producer. Prior to joining Ocelot, he was involved in a number of independent business ventures. Mr. Wade serves on the board of Kinder Morgan Canada Limited and also serves on the boards of several private companies including Novinium, Inc. and Belkin Enterprises Ltd., and is a member of the Advisory Board of Northbridge Capital Partners and a participant of AEA Investors groups of funds. In addition, Mr. Wade is a member of the Dean's Advisory Council of the John F. Kennedy School of Government at Harvard University and the Buck Advisory Council of The Buck Institute for Research on Aging. Mr. Wade earned a Bachelor of Commerce Degree from the University of Calgary in 1974 and received his Chartered Accountant designation in 1977. In 2012, Mr. Wade became a Fellow of the Institute of Chartered Accountants of British Columbia.

Qualifications: Mr. Wade's extensive executive experience provides the Board with strong leadership and decision-making capabilities. Having served as chief executive officer of two public companies, Mr. Wade has deep knowledge of key business issues, including finance and capital markets.

Mr. Wade has been a director of the Company since June 2015.

2. SENIOR MANAGEMENT TEAM

In addition to the Chief Executive Officer, each of the following persons are members of the Company's senior management team:

Name	Position
Ryan Ellson	Chief Financial Officer
Ed Caldwell	Vice President, Health, Safety and Environment & Corporate Social Responsibility
James Evans	Vice President, Corporate Services
Alan Johnson	Vice President, Asset Management
Glen Mah	Vice President, Business Development
Susan Mawdsley	Vice President, Finance and Corporate Controller
Rodger Trimble	Vice President, Investor Relations
Lawrence West	Vice President, Exploration

The business address of each member of the Company's senior management is 900, 520 - 3 Avenue SW, Calgary, Alberta, Canada T2P 0R3.

The management expertise and experience of such members of the Company's senior management are set out below.

Ryan Ellson, Chief Financial Officer

Mr. Ellson has been Gran Tierra's Chief Financial Officer since May 2015. Mr. Ellson has 17 years of experience in a broad range of international corporate finance and accounting roles. Mr. Ellson was chief financial officer of Onza Energy Inc. from January 2015 to May 2015. From July 2014 until December 2014 Mr. Ellson was Head of Finance for Glencore E&P (Canada) and prior thereto Vice President, Finance at Caracal Energy Inc., a London Stock Exchange listed company with operations in Chad, Africa from August 2011 until 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 a reserve based lending facility 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 Accountant and holds a Bachelor of Commerce and a Master of Professional Accounting from the University of Saskatchewan.

Ed Caldwell, Vice President, Health, Safety and Environment & Corporate Social Responsibility

Mr. Caldwell has been Gran Tierra's Vice President, Health, Safety and Environment & Corporate Social Responsibility, since June 2016. Mr. Caldwell had a distinguished 27-year career with ExxonMobil and Imperial Oil, and most recently worked with Caracal Energy Inc. in Caracal's efforts and achievement in Chad. Mr. Caldwell has extensive experience in senior Regulatory Approvals and HSE Management roles in Canada, Asia, Russia, and Africa. He has also worked with the Government of Canada and, in that capacity, represented Canada at the OECD Energy/Environment Committee as well as at the Intergovernmental Panel on Climate Change. Mr. Caldwell graduated in Chemical Engineering (Distinction) from Dalhousie University.

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 12 years in the international oil and gas industry. Most recently, Mr. Evans was the Head of Compliance & Corporate Services for Glencore E&P (Canada) from July 2014 to December 2014, and prior thereto Vice President of Compliance & Corporate Services at Caracal Energy from July 2011 to June 2014, in each case 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 in excess of 400 as Caracal Energy exceeded 20,000 barrels of oil per day 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 is a Certified General Accountant and holds a Bachelor of Commerce degree from the University of Calgary.

Alan Johnson, Vice President, Asset Management

Mr. Johnson has been Gran Tierra's Vice President, Asset Management, since May 2015. Mr. Johnson is a professional engineer with more than 20 years of experience working internationally in the oil and gas industry. His experience includes varied technical, managerial and executive roles in drilling, production, reservoir, reserves, corporate planning and asset management. Most recently Mr. Johnson was Head of Asset Management for Glencore E&P (Canada) from April 2014 to April 2015, where he was responsible for all development activities in Chad and prior thereto Director of Asset Management at Caracal Energy from August 2011 to March 2014, where he was responsible for development activities in the Doba basin in Chad, Africa. Mr. Johnson was instrumental in developing oil and gas assets in remote areas of southern Chad, achieving first production in less than 18 months. Mr. Johnson started his E&P career with Shell International in the Dutch North Sea. He then held positions of increasing responsibility with Shell Canada, APF Energy, Rockyview Energy, Delphi Energy and BG Australia. Mr. Johnson graduated with a 1st Class B. Eng (Hons) from Heriot Watt University in Scotland. Mr. Johnson is a Chartered Engineer in the UK and a Professional Engineer in Alberta.

Glen Mah, Vice President, Business Development

Mr. Mah has been Gran Tierra's Vice President, Business Development since June 2016. He is a Petroleum Geologist with extensive management experience covering the execution of exploration programs, field development and asset management for conventional and unconventional hydrocarbons. He has worked with onshore and offshore projects in various petroleum basins in the Americas, Africa, Middle East and Asia. Mr. Mah was the Chief Geologist with the highly successful Tanganyika Oil Company Ltd. Mr. Mah has Alberta-registered Professional designation with APEGA and holds a Bachelor of Science degree Specialization in Geology from the University of Alberta.

Susan Mawdsley, Vice President, Finance and Corporate Controller

Ms. Mawdsley has been Gran Tierra's Vice President, Finance, since June 2016, and has been Gran Tierra's Corporate Controller since 2012. She is a Chartered Accountant with 25 years of experience in the oil and gas industry. She has direct responsibility for the finance departments in all business units, as well as internal audit. Prior to joining Gran Tierra in 2011, she was an independent consultant providing contract controller, CFO, and other finance related services to publicly traded domestic and international oil and gas companies. Ms. Mawdsley is a Chartered Accountant and holds a Bachelor of Music in Performance degree from the University of Toronto.

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 30 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 thirty-five 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 multidisciplinary team to assess resources and grow reserves in the interior rift basins within Chad and led a successful exploration programme. 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. Mr. West 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 characterisation, in multi-disciplinary teams, and as a technical mentor to exploration teams. Mr. West has an Honours Bachelor of Science in Geology from McMaster University and an MBA, specialising in economics, from the University of Calgary.

3. CORPORATE GOVERNANCE

The Company is committed to good corporate governance practices, which promote the long-term interests of its stockholders and strengthens the Board and management accountability.

The Company is subject to the governance rules and guidelines for public companies established by securities regulators in both the United States and Canada. All directors, officers and Group employees are subject to the Group's Code of Business Conduct and Ethics, which sets out the Group's expectations and standards of behaviour. No waivers from the Code of Business Conduct and Ethics have been granted to date. In addition, the governance practices of the Company are set out in the Group's Corporate Governance Guidelines, which establish good governance practices including the following:

- Independent Chairman of the Board
- Annual elections of the entire Board
- Majority voting for directors with resignation policy
- 100% independent Committee members
- Annual self-evaluation of the Board
- Stock ownership guidelines for directors and officers
- No Tax Gross-Up provisions in any new executive agreements
- Policy prohibiting speculative trading of the Company's stock

- Clawback policy
- Stockholders may call special meetings of stockholders
- No stockholder poison pill rights (or similar)
- Regular executive sessions of independent directors
- Stockholders have the right to fill director vacancies caused by director removal

4. BOARD COMMITTEES

The Board has five standing committees: an Audit Committee, a Compensation Committee, a Health, Safety and Environment Committee, a Nominating and Corporate Governance Committee, and a Reserves Committee. Members serve on these committees until their resignation or until otherwise determined by the Board.

The committees regularly report their activities and actions to the full Board, generally at the next Board meeting following the committee meeting. Each of the committees operates under a charter approved by the Board. Current copies of the charters of the committees are available on the Company's website at www.grantierra.com/governance.

4.1 Audit Committee

The Board has determined that each of the members of the Audit Committee satisfies the requirements for audit committee independence and financial literacy under the rules and regulations of the NYSE American and the United States Securities and Exchange Commission (the **"SEC"**). The Board has determined that Mr. Hodgins and Smith are financial experts as defined in Item 407(d)(5) of Regulation S-K established by the SEC. The Audit Committee held four meetings during the fiscal year ended 31 December 2017.

The Audit Committee oversees the accounting and financial reporting process and the audit of the Company's financial statements, and assists the Board in monitoring the financial systems and Gran Tierra's legal and regulatory compliance. The Audit Committee met four times in 2017 and at each meeting met with the Group's independent auditors and the internal auditor, both privately and in the presence of management. The Audit Committee is responsible for, among other things:

- Evaluation and retention of Auditors;
- Approval of audit engagements;
- Approval of non-audit services;
- Review of audited financial statements and management's discussion and analysis;
- Review of quarterly financial statements;
- Review of earnings press releases;
- Review of accounting principles and policies;
- Review of guidelines and policies with respect to risk assessment and risk management;
- Review of the scope, adequacy and effectiveness of internal control over financial reporting;
- Review and oversee the internal audit function; and
- Approval of the Company's hedging policies and procedures.

The Audit Committee operates under a written charter that was adopted by the Board and satisfies the applicable standards of the SEC and the NYSE American.

The Audit Committee currently comprises three members: David P. Smith (Chair), Robert B. Hodgins and Ronald W. Royal.

4.2 Compensation Committee

The Board has determined that each of the members of the Compensation Committee satisfies the requirements for compensation committee independence under the rules and regulations of the NYSE American and the SEC. The Compensation Committee held three meetings during the fiscal year ended 31 December 2017.

The Compensation Committee acts on behalf of the Board to review, recommend for adoption and oversee Gran Tierra's compensation strategy, policies, plans and programs. The Compensation Committee is responsible for, among other things:

- Review and approve the components of compensation for the Chief Executive Officer and other executive officers;
- Review and approve the corporate goals and objectives relevant to the compensation for the Chief Executive Officer and other executive officers;
- Evaluate the performance of the Chief Executive Officer and other executive officers in light of established goals and objectives;
- Establish policies with respect to equity compensation arrangements;
- Review the risks arising from the Group's compensation policies and practices;
- Review and approve the compensation and other terms of employment or service, including severance and change-in-control arrangements, of Gran Tierra's Chief Executive Officer and the other executive officers;
- Oversee Gran Tierra's equity compensation plans for employees and directors;
- Evaluate and make recommendations regarding director compensation;
- Select compensation consultants and other advisors; and
- Review the Compensation Discussion and Analysis.

The Compensation Committee operates under a written charter that was adopted by the Board and satisfies the applicable standards of the SEC and the NYSE American.

The Compensation Committee comprises three members: Brooke Wade (Chair), Peter J. Dey and Robert B. Hodgins.

4.3 Health, Safety and Environment Committee

The Board has determined that each of the members of the Health, Safety and Environment Committee satisfies the requirements for independence under the rules and regulations of the NYSE American. The Health, Safety and Environment Committee held four meetings during the fiscal year ended 31 December 2017.

The Health, Safety and Environment Committee acts on behalf of the Board and assists the Board in fulfilling its responsibilities in relation to environmental, health and safety matters, including monitoring and overseeing the Company's policies and procedures for ensuring compliance by the Company with environmental regulatory requirements and ensuring that employees are provided with a safe environment in which to perform their duties. The Health, Safety and Environment Committee is responsible for, among other things:

- Develop and approve the environmental, health and safety goals and objectives of the Company;

- Review and monitor the environmental policies and activities of the Company to ensure that the Company is in compliance with environmental laws and legislation and that the Company conforms with industry standards;

- Review and monitor the health and safety policies and activities of the Company;

- Review environmental, health and safety compliance issues and incidents of non-compliance to determine that the Company is taking all necessary action in respect of those matters and that the Company has been diligent in carrying out its responsibilities and activities in that regard;

- Review significant external or internal audit or consultants' reports relating to environmental, health or safety matters; and

- Review significant legislative and regulatory changes including policy proposals and modifications that could impact the Company.

The Health, Safety and Environment Committee operates under a written charter that was adopted by the Board. The Health, Safety and Environment Committee comprises four members: Evan Hazell (Chair), Ronald W. Royal, Sondra Scott and David P. Smith.

4.4 **Reserves Committee**

The Board has determined that each of the members of the Reserves Committee satisfies the requirements for independence under the rules and regulations of the NYSE American. The Reserves Committee held three meetings during the fiscal year ended 31 December 2017.

The Reserves Committee acts on behalf of the Board and assists the Board in fulfilling its oversight responsibilities with respect to evaluating and reporting on the Company's oil and gas reserves. The Reserves Committee is responsible for, among other things:

- Approve the engagement of the independent reserves evaluators and their compensation;

- Review disclosure procedures with respect to the oil and gas activities of the Company;

- Review the Company's procedures for providing information to the independent reserves evaluator;

- Meet in-camera with the independent reserves evaluators; and

- Make recommendations to the Board regarding the approval of the Company's year-end reserves evaluations.

The Reserves Committee operates under a written charter that was adopted by the Board. The Reserves Committee comprises four members: Ronald W. Royal (Chair), Evan Hazell, Sondra Scott and Brooke Wade.

4.5 **Nominating and Corporate Governance Committee**

The Board has determined that each of the members of the Nominating and Corporate Governance Committee satisfies the requirements for independence under the rules and regulations of the NYSE American. The Nominating and Corporate Governance Committee held two meetings during the fiscal year ended 31 December 2017.

The Nominating and Corporate Governance Committee acts on behalf of the Board to identify, review and evaluate candidates to serve as directors of Gran Tierra, making recommendations to the Board regarding corporate governance issues, assessing the performance of the Board and management, and developing a set of corporate governance principles for Gran Tierra. The Nominating and Corporate Governance Committee is responsible for, among other things:

- Identify and review director nominees;

- Consider recommendations for Board nominees and proposals submitted by the Company's stockholders;
- Assess the performance of the Board;
- Recommend chair and membership of board committees;
- Review director independence;
- Consider and review continuing education for directors;
- Review and assess the Group's Corporate Governance Guidelines;
- Review succession planning for Gran Tierra's Chief Executive Officer and other executive officers; and
- Review insurance coverage for the directors and executive officers.

The Nominating and Corporate Governance Committee operates under a written charter that was adopted by the Board and satisfies the applicable standards of the SEC and the NYSE American. The Nominating and Corporate Governance Committee comprises four members: Peter J. Dey (Chair), Robert B. Hodgins, Sondra Scott and Brooke Wade.

5. SECURITIES DEALING CODE

The Company maintains a "Stock Trading by Officers, Directors and Other Designated Persons Policy" governing securities transactions by officers, directors, and other members of management of the Company which prohibits engaging in short sales, transactions in put or call options, hedging transactions or other inherently speculative transactions with respect to its stock at any time. In addition, Gran Tierra's "Trading on the Basis of Inside Information Policy", among other things, prohibits the Group's officers, including NEOs, directors and employees from trading during quarterly and special blackout periods.

PART III – SELECTED HISTORICAL FINANCIAL INFORMATION

The tables below present selected historical financial information of the Group as at and for the financial years ended 31 December 2015, 2016 and 2017 and the six month periods ended 30 June 2017 and 2018. Unless otherwise indicated, the selected historical financial information has been extracted without material adjustment from the Group's historical financial information set out in Appendix 1 (*Historical Financial Information*). Prospective investors should read the whole of this Prospectus and not rely on the selected information in this Part III (*Selected Historical Financial Information*).

1. CONSOLIDATED STATEMENTS OF OPERATIONS

	Years ended 31 December		
	2017	**2016**	**2015**
	(*In thousands, except per share data*)		
OIL AND NATURAL GAS SALES	$ 421,734	$ 289,269	$ 276,011
EXPENSES			
Operating	109,869	86,925	75,565
Transportation	25,107	31,776	40,204
Depletion, depreciation and accretion	131,335	139,535	176,386
Asset impairment	1,514	616,649	323,918
General and administrative	39,014	33,218	32,353
Severance	1,287	1,319	8,990
Transaction	-	7,325	-
Equity tax	1,224	3,098	3,769
Foreign exchange loss (gain)	2,067	(1,469)	(17,242)
Financial instruments loss	15,929	10,279	2,027
Other gain	-	-	(502)
Interest expense	13,882	14,145	-
	341,228	942,800	645,468
(LOSS) ON SALE AND GAIN ON ACQUISITION	(44,385)	929	-
INTEREST INCOME	1,209	2,368	1,369
INCOME (LOSS) BEFORE INCOME TAXES	37,330	(650,234)	(368,088)
INCOME TAX EXPENSE (RECOVERY)			
Current	24,322	20,122	15,383
Deferred	44,716	(204,791)	(115,442)
	69,038	(184,669)	(100,059)
NET LOSS AND COMPREHENSIVE LOSS	$ (31,708)	$ (465,565)	$ (268,029)
NET LOSS PER SHARE - BASIC AND DILUTED			
- BASIC AND DILUTED	$ (0.08)	$ (1.45)	$ (0.94)
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC AND DILUTED	396,683,593	320,851,538	285,333,869

	Six months ended 30 June (unaudited)	
	2018	2017
	(*In thousands, except per share data*)	
OIL AND NATURAL GAS SALES	$ 301,674	$ 190,787
EXPENSES		
Operating	61,324	51,145
Transportation	13,519	13,434
Depletion, depreciation and accretion	86,068	58,689
General and administrative	24,373	18,225
Equity tax	-	1,224
Foreign exchange loss	982	2,050
Financial instruments loss (gain)	11,714	(6,886)
Interest expense	12,870	6,426
	210,850	144,307
LOSS ON SALE	(292)	(9,076)
INTEREST INCOME	1,396	653
INCOME BEFORE INCOME TAXES	91,928	38,057
INCOME TAX EXPENSE		
Current	17,116	9,189
Deferred	36,651	22,904
	53,767	32,093
NET INCOME AND COMPREHENSIVE INCOME	$ 38,161	$ 5,964
NET INCOME (LOSS) PER SHARE - BASIC AND DILUTED		
- BASIC AND DILUTED	$ 0.10	$ 0.01
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC	391,173,460	398,795,023
WEIGHTED AVERAGE SHARES OUTSTANDING - DILUTED	427,242,014	398,816,091

2. **CONSOLIDATED BALANCE SHEETS**

	As at 30 June 2018 (Unaudited)	As at 31 December		
		2017	2016	2015
	(*In thousands*)			
Cash and cash equivalents	$ 125,807	$ 12,326	$ 25,175	$ 145,342
Total current assets	302,369	145,245	131,685	234,440
Total property and equipment, net	1,178,196	1,099,224	1,066,609	788,993
Total other long-term assets	141,520	185,150	169,602	122,685
Total assets	1,622,085	1,429,619	1,367,896	1,146,118
Total current liabilities	169,438	156,969	155,029	73,991
Total long-term liabilities	477,358	336,315	353,880	70,485
Total shareholders' equity	975,289	936,335	858,987	1,001,642
Total liabilities and shareholders' equity	1,622,085	1,429,619	1,367,896	1,146,118

3. **SUMMARY CONSOLIDATED STATEMENTS OF CASH FLOWS**

	Year ended 31 December		
	2017	**2016**	**2015**
		(*In thousands*)	
Net cash provided by (used in):			
Operating activities	$ 189,644	$ 93,042	$ 62,305
Investing activities	(243,803)	(605,932)	(233,483)
Financing activities	39,127	407,052	(9,277)
Net decrease in cash, cash equivalents and restricted cash and cash equivalents	(16,589)	(105,484)	(186,971)
Cash, cash equivalents and restricted cash and cash equivalents, end of year	$ 26,678	$ 43,267	$ 148,751

	Six Months Ended 30 June	
	2018	**2017**
	(*In thousands, unaudited*)	
Net cash provided by (used in):		
Operating activities	$ 130,934	$ 67,536
Investing activities	(166,330)	(95,881)
Financing activities	139,712	55,304
Net increase in cash, cash equivalents and restricted cash and cash equivalents	104,247	25,784
Cash, cash equivalents and restricted cash and cash equivalents, end of period	$ 130,925	$ 69,051

PART IV – OPERATING AND FINANCIAL REVIEW

The following discussion of the Group's financial condition and results of operations should be read in conjunction with the Group's historical financial information as at and for the financial years ended 31 December 2015, 2016 and 2017 and the six month periods ended 30 June 2017 and 2018 and the accompanying notes included in Appendix 1 (*Historical Financial Information*) and with the information relating to the Group's business included in Part I (*Information on Gran Tierra*). The discussion includes forward-looking statements that reflect the current view of the Group's management and involve risks and uncertainties. The Group's actual results could differ materially from those contained in any forward-looking statements as a result of factors discussed below and elsewhere in this Prospectus, particularly in the sections headed "*Risk Factors*" and "*Important Information–Information regarding forward-looking statements*". Prospective investors should read the whole of this Prospectus and not just rely upon summarised information set out in this Part IV (*Operating and Financial Review*).

1. OVERVIEW

Gran Tierra is a company focused on oil and gas exploration and production in Colombia. The Group's Colombian properties represented 100% of the Group's proved reserves NAR at 31 December 2017. For the year ended 31 December 2017, 98% (year ended 31 December 2016 - 97%; year ended 31 December 2015 - 97%) of the Group's revenue and other income was generated in Colombia. The Group is headquartered in Calgary, Alberta, Canada.

As of 31 December 2017, the Group had estimated proved reserves NAR of 59.3 MMBOE, of which 67% were proved developed reserves and 99% were oil.

In 2017, the Group sold its assets in Brazil and Peru, acquired a minority interest in PetroTal (which operates assets in Peru), and completed certain asset acquisitions and dispositions to further enhance its strategy.

2. FINANCIAL AND OPERATIONAL HIGHLIGHTS

2.1 Key Highlights for the six months ended 30 June 2018[1]

- Achieved a new company milestone: record Colombia working interest production before royalties of 35,239 BOEPD, 20% higher compared with 29,294 BOEPD in the first half of 2017. Production increased largely because of production from development activities in the Acordionero Field.

- The quarter's Colombia production was also up 57% from second quarter 2015 when the strategy to refocus Gran Tierra on Colombia began, an annual growth rate of 16%.

- Since acquiring the Acordionero Field in the MMV Basin in August 2016, the Group has increased production 274% to a record high average rate during the quarter of 17,710 bopd (14,076 bopd NAR). From the acquisition date of 23 August 2016, until 30 June 2018, the MMV assets have generated $327 million in oil and natural gas sales.

- Production NAR was 28,194 BOEPD, 15% higher than the first half of 2017.

- Continued significant exposure to oil price strength with oil representing 100% of the Group's production.

- Oil and natural gas sales volumes were 27,555 BOEPD, 13% higher than the first half of 2017. The increase in oil and gas sales volumes was driven by the production increase (5,945 bopd), partially offset by higher royalties (2,202 bopd) due to higher oil prices and a change in inventories (569 bopd).

[1] Except for net income, funds flow from operations and G&A expenses, all numbers and comparisons in this paragraph are based on Colombia only, excluding Brazil which was sold in 2017.

- Net income was $38.2 million compared with $6.0 million in the first half of 2017. Net loss in the comparative period included the loss on sale of Brazil business unit.

- Funds flow from operations increased by 76% to $169.3 million compared with the first half of 2017, while the Brent price increased only 35% from the first half of 2017.

- Active first half capital expenditures of $157.1 million. Funds flow from operations exceeded capital expenditures by $12.2 million.

- Oil and gas sales per BOE were $60.49, 46% higher than the first half of 2017.

- Operating netback per BOE was $45.48, 67% higher compared with the first half of 2017.

- Operating expenses per BOE were $12.30, 10% higher compared with the first half of 2017 as a result of payments triggered by renegotiating the Group's field operating agreements, power generation costs, equipment rental and accelerated maintenance costs, mainly in the Acordionero Field, in the period.

- Quality and transportation discount was $10.55 per BOE compared with $11.46 per BOE in the first half of 2017; this $0.91 per BOE reduction resulted from optimisation of transportation routes and narrowing of differentials

- Transportation expenses per BOE were $2.71, 8% lower compared with the first half of 2017. The decrease was due to the increased use of alternative transportation routes, which had lower costs per BOE.

- General and administrative (**"G&A"**) expenses before stock-based compensation per BOE decreased by 11% to $2.92 per BOE compared with the first half of 2017.

- Exited the first half of 2018 with $125.8 million of cash and cash equivalents.

2.2 Key Performance Indicators

The following table sets out a summary of key performance indicators for the Group's business for the financial years ended 31 December 2015, 2016 and 2017 and the six month periods ended 30 June 2017 and 2018.

(*Thousands of U.S. Dollars, unless otherwise indicated*)	**Six Months Ended 30 June**		
	2018	**2017**	**% Change**
Average Daily Volumes (BOEPD)			
Consolidated			
Working Interest Production Before Royalties	35,239	30,663	15
Royalties	(7,045)	(5,051)	39
Production NAR	28,194	25,612	10
Increase in Inventory	(639)	(61)	948
Sales(1)	27,555	25,551	8
Colombia			
Working Interest Production Before Royalties	35,239	29,294	20
Royalties	(7,045)	(4,843)	45
Production NAR	28,194	24,451	15
Increase in Inventory	(639)	(70)	813
Sales(1)	27,555	24,381	13
Net Income (Loss)	$38,161	$5,964	540
Operating Netback			
Oil and Natural Gas Sales	$301,674	$190,787	58
Operating Expenses	(61,324)	(51,145)	20

(*Thousands of U.S. Dollars, unless otherwise indicated*)	Six Months Ended 30 June		
	2018	2017	% Change
Transportation Expenses	(13,519)	(13,434)	1
Operating Netback[(2)]	$226,831	$126,208	80
G&A Expenses Before Stock-Based Compensation	$14,586	$15,173	(4)
G&A Stock-Based Compensation	9,787	3,052	221
G&A Expenses, Including Stock-Based Compensation	$24,373	$18,225	34
EBITDA[(2)]	$190,866	$103,172	85
Funds Flow From Operations[(2)]	$169,297	$95,946	76
Capital Expenditures	$157,088	$104,025	51

(*Thousands of U.S. dollars*)	As at		
	30 June 2018	31 December 2017	% Change
Cash and Cash Equivalents	$125,807	$12,326	921
Revolving Credit Facility	--	$148,000	(100)
Senior Notes	$300,000	--	--
Convertible Notes	$115,000	$115,000	--

(*Thousands of U.S. Dollars, unless otherwise indicated*)	Year ended 31 December				
	2017	% Change	2016	% Change	2015
Average Daily Volumes (BOEPD)					
Consolidated					
Working Interest Production Before Royalties	32,105	19	27,062	16	23,401
Royalties	(5,320)	37	(3,875)	(1)	(3,912)
Production NAR	26,785	16	23,187	19	19,489
Increase in Inventory	(96)	(113)	767	(162)	(1,229)
Sales[(1)]	26,689	11	23,954	31	18,260
Colombia					
Working Interest Production Before Royalties	31,426	20	26,216	15	22,794
Royalties	(5,217)	39	(3,746)	(2)	(3,822)
Production NAR	26,209	17	22,470	18	18,972
Increase in Inventory	(101)	(113)	771	(163)	(1,231)
Sales[(1)]	26,108	12	23,241	31	17,741
Net Income (Loss)	$(31,708)	93	$(465,565)	(74)	$(268,029)
Operating Netback					
Oil and Natural Gas Sales	$421,734	46	$289,269	5	$276,011
Operating Expenses	(109,869)	26	(86,925)	15	(75,565)
Transportation Expenses	(25,107)	(21)	(31,776)	(21)	(40,204)
Operating Netback[(2)]	$286,758	68	$170,568	6	$160,242
G&A Expenses Before Stock-Based Compensation	$29,775	10	$27,127	(9)	$29,780
G&A Stock-Based Compensation	$9,239	52	$6,091	137	$2,573
EBITDA[(2)]	$183,177	137	$(496,554)	(159)	$(191,702)
Funds Flow From Operations[(2)]	$220,197	110	$104,984	(2)	$107,570
Capital Expenditures	$251,041	96	$127,789	(18)	$156,639
Net Cash Received on Dispositions	$32,968	—	$—	—	$—

(*Thousands of U.S. Dollars, unless otherwise indicated*)	Year ended 31 December				
	2017	% Change	2016	% Change	2015
Cash Paid for Acquisitions, Net of Cash Acquired	$34,410	(93)	$507,584	—	$—

(*Thousands of U.S. dollars*)	As at 31 December				
	2017	% Change	2016	% Change	2015
Cash and Cash Equivalents and Current Restricted Cash and Cash Equivalents	$24,113	(28)	$33,497	(77)	$145,434
Revolving Credit Facility	$148,000	64	$90,000	—	$—
Convertible Senior Notes	$115,000	—	$115,000	—	$—

Notes:

(1) Sales volumes represent production NAR adjusted for inventory changes.

(2) **Non-GAAP measures**

Operating netback, EBITDA and funds flow from operations are non-GAAP measures which do not have any standardised 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. Gran Tierra's 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 and natural gas sales less operating and transportation expenses. Management believes that operating netback is a useful supplemental measure for management and investors to analyse financial performance and provides an indication of the results generated by the Group's principal business activities prior to the consideration of other income and expenses. A reconciliation from oil and natural gas 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. Management uses this supplemental measure to analyse performance and income or loss generated by the Group's principal business activities prior to the consideration of how non-cash items affect that income or loss, and believes that this financial measure is useful supplemental information for investors to analyse the Group's performance and its financial results. A reconciliation from net income (loss) to EBITDA is as follows:

(Thousands of U.S. Dollars)	Six Months Ended 30 June	
	2018	2017
Net income	$ 38,161	$ 5,964
Adjustments to reconcile net income to EBITDA		
DD&A expenses	86,068	58,689
Interest expense	12,870	6,426
Income tax expense	53,767	32,093
EBITDA (non-GAAP)	$ 190,866	$ 103,172

(Thousands of U.S. Dollars)	Year ended 31 December		
	2017	2016	2015
Net loss	$ (31,708)	$ (465,565)	$ (268,029)
Adjustments to reconcile net loss to EBITDA			
DD&A expenses	131,335	139,535	176,386
Interest expense	13,882	14,145	—
Income tax expense (recovery)	69,038	(184,669)	(100,059)
EBITDA (non-GAAP)	$ 182,547	$ (496,554)	$ (191,702)

Funds flow from operations, as presented, is defined as net income or loss adjusted for DD&A expenses, deferred tax expense, stock-based compensation expense, amortisation of debt issuance costs, cash settlement of RSUs, unrealised foreign exchange gains and losses, financial instruments gains or losses, cash settlement of financial instruments and loss on sale. Management uses this financial measure to analyse performance and income or loss generated by the Group's 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 analyse the Group's performance and its financial results. A reconciliation from net income or loss to funds flow from operations is as follows:

(Thousands of U.S. Dollars)	Six Months Ended 30 June	
	2018	2017
Net income	$ 38,161	$ 5,964
Adjustments to reconcile net income to funds flow from operations		
DD&A expenses	86,068	58,689
Deferred tax expense	36,651	22,904
Stock-based compensation expense	10,202	3,183
Amortisation of debt issuance costs	1,513	1,225
Cash settlement of RSUs	(360)	(501)
Unrealised foreign exchange loss	539	1,076
Financial instruments loss (gain)	11,714	(6,886)
Cash settlement of financial instruments	(15,483)	1,216
Loss on sale	292	9,076
Funds flow from operations (non-GAAP)	$ 169,297	$ 95,946

(Thousands of U.S. Dollars)	Year ended 31 December		
	2017	2016	2015
Net loss	$ (31,708)	$(465,565)	$(268,029)
Adjustments to reconcile net loss to funds flow from operations			
DD&A expenses	131,335	139,535	176,386
Asset impairment	1,514	616,649	323,918
Deferred tax expense (recovery)	44,716	(204,791)	(115,442)
Stock-based compensation expense	9,775	6,339	2,733
Amortisation of debt issuance costs	2,415	5,691	—
Cash settlement of RSUs	(564)	(1,234)	(1,392)
Unrealised foreign exchange loss (gain)	837	(1,428)	(8,380)
Financial instruments loss	15,929	10,279	2,027
Cash settlement of financial instruments	1,563	438	(3,749)
Loss on sale and (gain) on acquisition	44,385	(929)	—
Other gain	—	—	(502)
Funds flow from operations (non-GAAP)	$ 220,197	$ 104,984	$ 107,570

3. RESULTS OF OPERATION

3.1 Oil and Gas Production and Sales Volumes, BOEPD

(a) *Six months ended 30 June 2018 compared to six months ended 30 June 2017*

	Six Months ended 30 June 2018	Six Months ended 30 June 2017		
Average Daily Volumes (BOEPD)	**Total**	**Colombia**	**Brazil**	**Total**
Working Interest Production Before Royalties	35,239	29,294	1,369	30,663
Royalties	(7,045)	(4,843)	(208)	(5,051)
Production NAR	28,194	24,451	1,161	25,612
(Increase) Decrease in Inventory	(639)	(70)	9	(61)
Sales	27,555	24,381	1,170	25,551
Royalties,% of Working Interest Production Before Royalties	20%	17%	15%	16%

Oil and gas production NAR for the six months ended 30 June 2018 increased by 10% to 28,194 BOEPD compared with 25,612 BOEPD in the corresponding period of 2017.

Colombian oil and gas production NAR for the six months ended 30 June 2018 increased by 15%, compared with the corresponding period of 2017. The increase in production was a result of successful drilling and a workover campaign in the Acordionero and Costayaco Fields and the Vonu-1 exploration well. Working interest production before royalties from the Acordionero Field averaged 17,233 bopd before royalties (13,777 bopd NAR) during the six months ended 30 June 2018 compared with 7,286 bopd before royalties (6.402 bopd NAR) in the corresponding period of 2017, a 137% increase bopd before royalties. During the second quarter of 2018, four wells were brought on production. Production was negatively impacted by two Electronic Submersible Pumps (**"ESPs"**) failures in Acordionero and one ESP failure in Costayaco. Royalties as a percentage of production for the six months ended 30 June 2018 increased compared with the corresponding period of 2017 commensurate with the increase in oil prices due to price sensitive royalties payable in Colombia, higher API in the Acordionero Field and this field reaching the threshold for the HPR royalty.

(b) *Years ended 31 December 2017, 2016 and 2015*

	Year ended 31 December		
Average Daily Volumes (BOEPD) - Colombia	**2017**	**2016**	**2015**
Working Interest Production Before Royalties	31,426	26,216	22,794
Royalties	(5,217)	(3,746)	(3,822)
Production NAR	26,209	22,470	18,972
(Increase) Decrease in Inventory	(101)	771	(1,231)
Sales	26,108	23,241	17,741
Royalties,% of Working Interest Production Before Royalties	17%	14%	17%

Average Daily Volumes (BOEPD) - Brazil	**Year ended 31 December** **2017**	**2016**	**2015**
Working Interest Production Before Royalties	679	846	607
Royalties	(103)	(129)	(90)
Production NAR	576	717	517
(Increase) Decrease in Inventory	5	(4)	2
Sales	581	713	519
Royalties,% of Working Interest Production Before Royalties	15%	15%	15%

Average Daily Volumes (BOEPD) - Total	**Year ended 31 December** **2017**	**2016**	**2015**
Working Interest Production Before Royalties	32,105	27,062	23,401
Royalties	(5,320)	(3,875)	(3,912)
Production NAR	26,785	23,187	19,489
(Increase) Decrease in Inventory	(96)	767	(1,229)
Sales	26,689	23,954	18,260
Royalties,% of Working Interest Production Before Royalties	17%	14%	17%

Oil and gas production NAR for the year ended 31 December 2017 increased by 16% to 26,785 BOEPD compared with 23,187 BOEPD in 2016. The Group increased oil and gas production NAR despite the sale of the Group's Brazil business unit on 30 June 2017. Production increased as a result of a successful drilling and workover campaign in the Acordionero Field in Colombia, the successful Vonu-1 exploration well and a workover campaign in Cumplidor. Colombian NAR production for the year ended 31 December 2017 increased 17% compared with the prior year.

Royalties as a percentage of production for the year ended 31 December 2017 increased compared to prior year commensurate with the increase in oil prices, due to price sensitive royalties payable in Colombia.

Oil and gas production NAR for the year ended 31 December 2016 increased by 19% to 23,187 BOEPD compared with 19,489 BOEPD in 2015. Production increased as a result of the Petroamerica and PetroLatina acquisitions and a successful drilling campaign in the Costayaco, Moqueta and Acordionero Fields in Colombia.

3.2 **Operating Netbacks**

(a) *Six months ended 30 June 2018 compared to six months ended 30 June 2017*

	Six Months Ended 30 June 2018	**Six Months Ended 30 June 2017**		
(Thousands of U.S. Dollars)	**Total**	**Colombia**	**Brazil**	**Total**
Oil and Natural Gas Sales	$ 301,674	$ 182,369	$ 8,418	$ 190,787
Transportation Expenses	(13,519)	(13,084)	(350)	(13,434)
	288,155	169,285	8,068	177,353
Operating Expenses	(61,324)	(49,348)	(1,797)	(51,145)
Operating Netback(1)	$ 226,831	$ 119,937	$ 6,271	$ 126,208

U.S. Dollars Per BOE Sales Volumes NAR	Six Months Ended 30 June 2018	Six Months Ended 30 June 2017		
Brent	$ 71.04	$ 52.79	$ 52.79	$ 52.79
Vasconia, Quality and Transportation Discounts	(10.55)	(11.46)	(13.03)	(11.54)
Average Realised Price	60.49	41.33	39.76	41.25
Transportation Expenses	(2.71)	(2.96)	(1.65)	(2.90)
Average Realised Price Net of Transportation Expenses	57.78	38.37	38.11	38.35
Operating Expenses	(12.30)	(11.18)	(8.49)	(11.06)
Operating Netback(1)	$ 45.48	$ 27.19	$ 29.62	$ 27.29

Note:

(1) Operating Netback is a non-GAAP measure which does not have any standardised meaning prescribed under U.S. GAAP. Please see above at paragraph 2.2 of this Part IV (*Operating and Financial Review*) for a definition and reconciliation of this measure.

Oil and gas sales for the six months ended 30 June 2018 increased by 58% to $301.7 million compared with the corresponding period of 2017. The increases were due to increased sales volumes and realised oil prices. The following table shows the effect of changes in realised prices and sales volumes on the Group's oil and gas sales for the six months ended 30 June 2018 compared with the corresponding period in 2017:

	Six Months Ended 30 June 2018 Compared with Six Months Ended 30 June 2017
Oil and natural gas sales for the comparative period	$ 190,787
Realised sales price increase effect	95,920
Sales volume increase effect	14,967
Oil and natural gas sales for period ended 30 June 2018	$ 301,674

Average realised prices for the six months ended 30 June 2018 increased by 47% compared with the corresponding period of 2017. The increases were commensurate with increases in benchmark oil prices and lower quality and transportation discounts. Average Brent oil prices for the six months ended 30 June 2018 increased by 35% compared with the corresponding period of 2017.

The Group has options to sell its oil through multiple pipelines and trucking routes. Each transportation route has varying effects on realised sales prices and transportation expenses. The Group focuses on maximising operating netback. The following table shows the percentage of oil volumes the Group sold in Colombia using each transportation method for the six month periods ended 30 June 2017 and 2018:

	Six Months ended 30 June	
	2018	**2017**
Volume transported through pipeline	9%	22%
Volume sold at wellhead	42%	52%
Volume not sold at wellhead, trucking	49%	26%
	100%	100%

Volumes transported not sold at the wellhead receive higher realised prices, but incur higher transportation expenses. Volumes sold at the wellhead have the opposite effect of lower realised prices, offset by lower transportation expenses.

Total Company transportation expenses for the six months ended 30 June 2018 of $13.5 million were comparable with the corresponding period of 2017. On a per BOE basis, transportation expenses for the six months ended 30 June 2018 decreased by 7% to $2.71 from $2.90 compared with the corresponding period of 2017. The decrease was primarily due to the use of alternative transportation routes, which had lower costs per BOE.

Colombian transportation expenses for the six months ended 30 June 2018 on a per BOE basis decreased by 8% to $2.71 per BOE from $2.96 in the corresponding period of 2017. The decrease in Colombian transportation expenses per BOE was due to renegotiation of certain sales contracts, which had lower transportation costs compared to contracts used in 2017.

Transportation expenses for the six months ended 30 June 2018 increased 3% to $13.5 million compared with $13.1 million in the corresponding period of 2017. The increase was primarily due to higher volumes.

In addition to lower transportation expenses, the Group also achieved decreases in quality and transportation discounts. The following table shows the variance in the Group's average realised prices net of transportation expenses in Colombia for the six months ended 30 June 2018 compared with the corresponding period in 2017:

U.S. Dollars Per BOE Sales Volumes NAR		**Six Months Ended 30 June 2018 Compared with Six Months Ended 30 June 2017**
Average realised price net of transportation expenses for the comparative period	$	38.37
Increase in benchmark prices	$	18.25
Decrease in quality and transportation discounts		0.91
Decrease in transportation expenses		0.25
Average realised price net of transportation expenses for the period ended 30 June 2018	$	57.78

Total Company operating expenses for the six months ended 30 June 2018 increased by 20% to $61.3 million compared with total Company operating expenses in the corresponding period of 2017.

Colombian operating expenses for the six months ended 30 June 2018 on a per BOE basis increased by $1.12 compared with the corresponding period of 2017. Workover expenses decreased by $0.27 over the same period. Excluding workover expenses, Colombia operating expenses increased by $1.39 per BOE primarily as a result of payments triggered by renegotiating the Group's field operating agreements, power generation costs, equipment rental and accelerated maintenance costs mainly in the Acordionero field during the second quarter of 2018.

(b) *Years ended 31 December 2017, 2016 and 2015*

Colombia	**Year ended 31 December**					
(Thousands of U.S. Dollars)		**2017**		**2016**		**2015**
Oil and Natural Gas Sales	$	413,316	$	280,872	$	269,035
Transportation Expenses		(24,757)		(31,347)		(40,083)
		388,559		249,525		228,952
Operating Expenses		(108,072)		(84,794)		(69,323)
Operating Netback[(1)]	$	280,487	$	164,731	$	159,629
U.S. Dollars Per BOE Sales Volumes NAR						
Brent	$	54.82	$	44.33	$	52.35
Quality and Transportation Discounts		(11.45)		(11.31)		(10.80)
Average Realised Price		43.37		33.02		41.55

Transportation Expenses	(2.60)	(3.69)	(6.19)
Average Realised Price Net of Transportation Expenses	40.77	29.33	35.36
Operating Expenses	(11.34)	(9.97)	(10.71)
Operating Netback[(1)]	$ 29.43	$ 19.36	$ 24.65

Brazil	**Year ended 31 December**		
(Thousands of U.S. Dollars)	**2017**	**2016**	**2015**
Oil and Natural Gas Sales	$ 8,418	$ 8,397	$ 6,976
Transportation Expenses	(350)	(429)	(121)
	8,068	7,968	6,855
Operating Expenses	(1,797)	(2,131)	(6,242)
Operating Netback[(1)]	$ 6,271	$ 5,837	$ 613
U.S. Dollars Per BOE Sales Volumes NAR			
Brent	$ 54.82	$ 44.33	$ 52.35
Quality and Transportation Discounts	(15.06)	(12.11)	(15.51)
Average Realised Price	39.76	32.22	36.84
Transportation Expenses	(1.65)	(1.65)	(0.64)
Average Realised Price Net of Transportation Expenses	38.11	30.57	36.20
Operating Expenses	(8.49)	(8.18)	(32.97)
Operating Netback[(1)]	$ 29.62	$ 22.39	$ 3.23

Total	**Year ended 31 December**		
(Thousands of U.S. Dollars)	**2017**	**2016**	**2015**
Oil and Natural Gas Sales	$ 421,734	$ 289,269	$ 276,011
Transportation Expenses	(25,107)	(31,776)	(40,204)
	396,627	257,493	235,807
Operating Expenses	(109,869)	(86,925)	(75,565)
Operating Netback[(1)]	$ 286,758	$ 170,568	$ 160,242
U.S. Dollars Per BOE Sales Volumes NAR			
Brent	$ 54.82	$ 44.33	$ 52.35
Quality and Transportation Discounts	(11.53)	(11.33)	(10.94)
Average Realised Price	43.29	33.00	41.41
Transportation Expenses	(2.58)	(3.62)	(6.03)
Average Realised Price Net of Transportation Expenses	40.71	29.38	35.38
Operating Expenses	(11.28)	(9.92)	(11.34)
Operating Netback[(1)]	$ 29.43	$ 19.46	$ 24.04

Note:

(1) Operating Netback is a non-GAAP measure which does not have any standardised meaning prescribed under U.S. GAAP. Please see above at paragraph 2.2 of this Part IV (*Operating and Financial Review*) for a definition and reconciliation of this measure.

Oil and gas sales for the year ended 31 December 2017 increased to $421.7 million from $289.3 million in 2016 primarily as a result of the effect of increased sales volumes and realised oil prices. Oil and gas sales for the year ended 31 December 2016 increased to $289.3 million from $276.0 million in 2015 primarily as a result of the effect of increased sales volumes, partially offset by decreased average realised oil prices.

The following table shows the effect of changes in realised price and sales volumes on the Group's oil and gas sales for the three years ended 31 December 2017:

	Year ended 31 December					
	2017		2016		2015	
Oil and natural gas sales for the comparative period	$	289,269	$	276,011	$	559,398
Realised sales price increase (decrease) effect		100,304		(73,782)		(275,425)
Sales volume increase effect		32,161		87,040		(7,962)
Oil and natural gas sales for current period	$	421,734	$	289,269	$	276,011

Average realised prices increased by 31% to $43.29 per BOE for the year ended 31 December 2017 from $33.00 per BOE in 2016. The increase in realised prices was consistent with an increase in benchmark oil prices. Average Brent oil prices for the year ended 31 December 2017 increased by 24% compared with 2016.

Average realised prices decreased by 20% to $33.00 per BOE for the year ended 31 December 2016, from $41.41 per BOE in 2015. The decrease in realised prices was consistent with lower benchmark oil prices. Average Brent oil prices for the year ended 31 December 2016 decreased by 15% compared with 2015.

The Group has options to sell its oil through multiple pipelines and trucking routes. Each transportation route has varying effects on realised prices and transportation expenses. The following table shows the percentage of oil volumes the Group sold in Colombia using each transportation method for each of the three years ended 31 December 2017:

	Year ended 31 December		
	2017	2016	2015
Volume transported through pipeline	16%	44%	54%
Volume sold at wellhead	52%	43%	30%
Volume not sold at wellhead, trucking	32%	13%	16%
	100%	100%	100%

Volumes not sold at the wellhead receive a higher realised price, but incur higher transportation expenses. Volumes sold at the wellhead have the opposite effect of lower realised price, offset by lower transportation expense.

Transportation expenses for the year ended 31 December 2017 decreased by 21% to $25.1 million, compared with $31.8 million in 2016. On a per BOE basis, transportation expenses decreased 29% to $2.58 per BOE from $3.62 per BOE, in 2016. The decrease in transportation expenses per BOE was primarily due to a higher percentage of volumes sold at wellhead, as noted in the table above, and the use of alternative transportation routes, which had lower costs per BOE than the routes used in 2016.

Transportation expenses for the year ended 31 December 2016 decreased 21% to $31.8 million, compared with $40.2 million in 2015. On a per BOE basis, transportation expenses decreased 40% to $3.62 per BOE from $6.03 per BOE, in 2015. The decrease in transportation expenses per BOE was primarily due to a higher percentage of volumes sold at wellhead, as noted in the table above, and the use of alternative transportation routes, which had lower costs per BOE than the routes used in 2015.

The following table shows the variance in the Group's average realised prices net of transportation expenses in Colombia for each of the three years ended 31 December 2017:

U.S. Dollars Per BOE Sales Volumes
NAR

	Year ended 31 December		
	2017	**2016**	**2015**
Average realised price net of transportation expenses for the comparative period	$ 29.33	$ 35.36	$ 79.07
Increase in benchmark prices	10.49	(8.02)	(46.67)
(Increase) decrease in quality and transportation discounts	(0.14)	(0.51)	5.46
Decrease in transportation expenses	1.09	2.50	(2.50)
Average realised price net of transportation expenses for the period ended 30 June 2018	$ 40.77	$ 29.33	$ 35.36

Operating expenses for the year ended 31 December 2017 increased 26% to $109.9 million compared with $86.9 million in 2016. The increase was primarily due to higher sales volumes and an increase in operating costs per BOE.

In Colombia, operating costs for the year ended 31 December 2017 increased by $1.36 per BOE compared with 2016, primarily as a result of power disruptions in the Putumayo region relating to the Mocoa natural disaster and NaturAmazonas reforestation and conservation expenses.

Since the Mocoa natural disaster, the electrical system in the Putumayo region has experienced instability, and the Group has had to utilise gas and diesel generators to maintain production and injection at key wells during brief periods of electrical outage. The instability of electricity not only increases the Group's operating costs it also has a negative impact on the Group's production in the Putumayo basin and water injection program in both Costayaco and Moqueta. The Group is expanding a gas to electrical power facility in Costayaco which will enable consistent power generation.

On 30 January 2017, the Group signed an agreement with Conservation International to launch NaturAmazonas, a five year reforestation and conservation program to be implemented by Conservation International in the Putumayo Region of Colombia.

Conservation International is a non-government organisation, well-known for implementing and managing nature conservation projects around the world. During the year ended 31 December 2017, operating expenses included $3.2 million related to this program.

Operating expenses for the year ended 31 December 2016 were $86.9 million, or $9.92 per BOE, compared with $75.6 million, or $11.34 per BOE in 2015. On a per BOE basis, operating expenses decreased by 13%. The decrease in operating expenses per BOE in 2016 was primarily due to Colombian operating cost savings, partially offset by the effect of the weakening of the U.S. dollar against local currencies in South America. Workover expenses increased by $0.38 per BOE to $2.60 per BOE compared with the year ended 31 December 2015. Excluding workover expenses, operating costs decreased by $1.80 per BOE to $7.32 per BOE.

Colombian operating expenses for the year ended 31 December 2016 decreased by $0.74 per BOE compared with the corresponding period in 2015. Workover expenses increased by $0.38 per BOE. Excluding workover expenses, operating expenses in Colombia decreased by $1.12 per BOE.

3.3 **DD&A Expenses**

(a) *Six months ended 30 June 2018 compared to six months ended 30 June 2017*

	Six Months Ended 30 June 2018		Six Months Ended 30 June 2017	
	DD&A expenses, thousands of U.S. Dollars	**DD&A expenses, U.S. Dollars Per BOE**	**DD&A expenses, thousands of U.S. Dollars**	**DD&A expenses, U.S. Dollars Per BOE**
Colombia	$ 84,564	$ 16.96	$ 55,065	$ 12.48
Brazil	—	—	2,263	10.69
Peru	—	—	921	—
Corporate	1,504	—	440	—
	$ 86,068	$ 17.26	$ 58,689	$ 12.69

DD&A expenses for the six months ended 30 June 2018 increased to $86.1 million ($17.26 per BOE) from $58.7 million ($12.69 per BOE), respectively, in the corresponding period in 2017. On a per BOE basis, the increase was due to higher costs in the depletable base, partially offset by increased proved reserves. On a per BOE basis, DD&A expenses increased by 36% from $12.69 per BOE in the six months ended 30 June 2017, primarily due to higher costs in the depletable base.

(b) *Years ended 31 December 2017, 2016 and 2015*

	Year ended 31 December 2017		Year ended 31 December 2016		Year ended 31 December 2015	
	DD&A expenses, thousands of U.S. Dollars	**DD&A expenses, U.S. Dollars Per BOE**	**DD&A expenses, thousands of U.S. Dollars**	**DD&A expenses, U.S. Dollars Per BOE**	**DD&A expenses, thousands of U.S. Dollars**	**DD&A expenses, U.S. Dollars Per BOE**
Colombia	$ 126,453	$ 13.27	$ 132,569	$ 15.59	$ 167,701	$ 25.90
Brazil	2,263	10.69	3,819	14.65	6,183	32.66
Peru	1,483	—	544	—	789	—
Corporate	1,136	—	2,603	—	1,713	—
	$ 131,335	$ 13.48	$ 139,535	$ 15.92	$ 176,386	$ 26.47

DD&A expenses for the year ended 31 December 2017 decreased to $131.3 million ($13.48 per BOE) from $139.5 million ($15.92 per BOE) in 2016, and from $176.4 million ($26.47 per BOE) in 2015. On a per BOE basis, the decreases in both years were due to increased proved reserves at year-end and lower costs in the depletable base in 2016.

3.4 **Asset Impairment**

	Year ended 31 December		
(Thousands of U.S. Dollars)	**2017**	**2016**	**2015**
Impairment of oil and gas properties			
Colombia	$ —	$ 513,650	$ 232,436
Brazil	—	71,143	46,933
Peru	890	31,192	41,916
Mexico	624	—	—
	1,514	615,985	321,285
Impairment of inventory	—	664	2,633
	$ 1,514	$ 616,649	$ 323,918

The Group 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 during the 12 months period prior to the ending date of the period covered by the balance sheet, calculated as an unweighted arithmetic average of the first-day-of-the month price for each month within such period for that oil and natural gas. That average price is then held constant, except for changes which are fixed and determinable by existing contracts. 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 the Group's reserves.

In the year ended 31 December 2017, no ceiling test impairment was recorded in the Group's Colombia cost centre. In accordance with U.S. GAAP, the Group used an average Brent price of $54.19 per bbl for the purposes of the 31 December 2017, ceiling test calculation (30 September 2017 - $52.70; 30 June 2017 - $51.35, 31 March 2017 - $49.33; 31 December 2016 - $42.92; 30 September 2016 - $42.23; 30 June 2016 - $44.48, 31 March 2016 - $48.79; 31 December 2015 - $54.08).

In the year ended 31 December 2016, ceiling test impairment losses in the Group's Colombia cost centre and inventory impairment losses were primarily due to lower oil prices and because the acquisitions of PetroLatina and Petroamerica were initially added into the cost base at fair value. These acquired assets were then subjected to a prescribed U.S. GAAP ceiling test, which is not a fair value test, and which, as noted above, uses constant commodity pricing that averages prices during the preceding 12 months. The ceiling test impairment loss in the Group's Brazil cost centre related to lower oil prices and increased costs in the depletable base as a result of a $45.0 million impairment of unproved properties. Impairment losses in the Group's Peru cost centre included costs incurred on Block 95 and an impairment of costs incurred on Blocks 123 and 129.

In the year ended 31 December 2015, ceiling test impairment losses in the Group's Colombia and Brazil cost centres and inventory impairment losses were primarily due to lower oil prices. Impairment losses in the Group's Peru cost centre related to costs incurred on Block 95.

3.5 G&A Expenses

(a) *Six months ended 30 June 2018 compared to six months ended 30 June 2017*

	Six Months Ended 30 June		
(Thousands of U.S. Dollars)	**2018**	**2017**	**% Change**
G&A Expenses Before Stock-Based Compensation	$ 14,586	$ 15,173	(4)
G&A Stock-Based Compensation	9,787	3,052	221
G&A Expenses, Including Stock-Based Compensation	$ 24,373	$ 18,225	34
U.S. Dollars Per BOE Sales Volumes NAR			
G&A Expenses Before Stock-Based Compensation	$ 2.92	$ 3.28	(11)
G&A Stock-Based Compensation	1.96	0.66	197
G&A Expenses, Including Stock-Based Compensation	$ 4.88	$ 3.94	24

For the six months ended 30 June 2018, G&A expenses before stock-based compensation decreased by 4% from the corresponding period of 2017. The decrease was primarily the result of higher overhead recoveries, partially offset by increase in Colombia and Corporate G&A expenses commensurate with the Group's growth. On a per BOE basis, G&A expenses before stock-based compensation decreased 11% from the corresponding period of 2017.

After stock-based compensation, G&A expenses for the six months ended 30 June 2018 increased by 34% to $24.4 million compared with the corresponding period in 2017 mainly due to higher G&A Stock-Based Compensation resulting from a higher share price at 30 June 2018.

(b) *Years ended 31 December 2017, 2016 and 2015*

(Thousands of U.S. Dollars)	Year ended 31 December 2017	% Change	2016	% Change	2015
G&A Expenses Before Stock-Based Compensation	$ 29,775	10%	$ 27,127	(9)%	$ 29,780
G&A Stock-Based Compensation	9,239	52%	6,091	137%	2,573
G&A Expenses, Including Stock-Based Compensation	$ 39,014	17%	$ 33,218	3%	$ 32,353
U.S. Dollars Per BOE Sales Volumes NAR					
G&A Expenses Before Stock-Based Compensation	$ 3.06	(1)%	$ 3.10	(30)%	$ 4.46
G&A Stock-Based Compensation	0.95	38%	0.69	77%	0.39
G&A Expenses, Including Stock-Based Compensation	$ 4.01	6%	$ 3.79	(22)%	$ 4.85

G&A expenses before stock-based compensation for the year ended 31 December 2017 increased by 10% to $29.8 million ($3.06 per BOE) from $27.1 million ($3.10 per BOE) in 2016. The increase was commensurate with the Group's growth. Since 31 December 2016, the Group drilled 25 wells and grew production NAR 16% from 23,187 BOEPD in 2016 to 26,785 BOEPD in 2017. G&A expenses before stock-based compensation per BOE was consistent with 2016 and decreased 31% from 2015. After stock-based compensation, G&A expenses for the year ended 31 December 2017 increased by 17% to $39.0 million from $33.2 million in 2016. The increase was mainly as a result of PSUs and DSUs granted during 2017 combined with the increase in the stock price during the fourth quarter of 2017.

G&A expenses before stock-based compensation for the year ended 31 December 2016 decreased by 9% to $27.1 million ($3.10 per BOE) from $29.8 million ($4.46 per BOE) in 2015. These decreases were mainly due to savings due to cost control initiatives. After stock-based compensation, G&A expenses for the year ended 31 December 2016 increased by 3% to $33.2 million ($3.79 per BOE) from $32.4 million ($4.85 per BOE) in 2015. The increase was mainly as a result of Performance Stock Units ("PSUs") and deferred share units ("DSUs") granted during 2016 and a higher year-end share price.

Severance Expenses

For the year ended 31 December 2017, severance expenses were $1.3 million compared with $1.3 million and $9.0 million, respectively, in 2016 and 2015. Severance expenses were consistent with the decrease in headcount.

Transaction Expenses

For the year ended 31 December 2017, transaction expenses were nil, compared with $7.3 million in 2016 and nil in 2015.

Transaction expenses in 2016 related to the Group's acquisitions of PetroLatina and Petroamerica.

Equity Tax Expense

For the years ended 31 December 2017, 2016 and 2015, equity tax expense was $1.2 million, $3.1 million and $3.8 million, respectively, and was calculated based on the Group's Colombian legal entities' balance sheet at 1 January.

3.6 **Foreign Exchange Losses**

(a) *Six months ended 30 June 2018 compared to six months ended 30 June 2017*

For the six months ended 30 June 2018 the Group had foreign exchange losses of $1.0 million compared with $2.1 million in the corresponding period of 2017. Deferred taxes are considered a monetary liability and require translation from local currency to U.S. dollar functional currency at each balance sheet date. This translation was the main source of the foreign exchange gains and losses. Due to the long-term nature of deferred tax liabilities, the related foreign exchange losses are not expected to be realised in the near-term.

The following table presents the change in the U.S. dollar against the Colombian peso for the six months ended 30 June 2018, and 2017:

	Six Months Ended 30 June	
	2018	**2017**
Change in the U.S. dollar against the Colombian peso	weakened by 2%	strengthened by 1%

(b) *Years ended 31 December 2017, 2016 and 2015*

For the years ended 31 December 2017, 2016 and 2015, the Group had foreign exchange losses of $2.1 million and gains of $1.5 million and $17.2 million, respectively. Under GAAP, deferred taxes are considered a monetary liability and require translation from local currency to U.S. dollar functional currency at each balance sheet date. This translation was the main source of the foreign exchange losses and gains.

The following table presents the change in the Colombian peso against the U.S. dollar for each of the three years ended 31 December 2017:

	Year ended 31 December		
	2017	**2016**	**2015**
Change in the U.S. dollar against the Colombian peso	strengthened by 1%	strengthened by 5%	weakened by 32%

3.7 **Financial Instrument Gains and Losses**

(a) *Six months ended 30 June 2018 compared to six months ended 30 June 2017*

The following table presents the nature of the Group's financial instruments gains and losses for the six months ended 30 June 2018, and 2017:

	Six Months Ended 30 June	
(Thousands of U.S. Dollars)	**2018**	**2017**
Commodity price derivative loss (gain)	$ 19,455	$ (6,247)
Foreign currency derivatives loss (gain)	(2,024)	(639)
Investment gain	(5,717)	—
	$ 11,714	$ (6,886)

(b) *Years ended 31 December 2017, 2016 and 2015*

The following table presents the nature of the Group's financial instruments gains and losses for each of the three years ended 31 December 2017:

	Year ended 31 December		
(Thousands of U.S. Dollars)	**2017**	**2016**	**2015**
Commodity price derivative loss (gain)	$ 17,327	$ 7,370	$ —
Foreign currency derivatives loss (gain)	(1,287)	(1,016)	692
Investment gain	(111)	—	—
Trading securities loss	—	3,925	1,335
	$ 15,929	$ 10,279	$ 2,027

3.8 Loss on Sale of Business Units and Gain on Acquisition

Loss on sale of business units for the year ended 31 December 2017, related to the sale of the Group's Brazil business unit on 30 June 2017 and the Group's Peru business unit on 18 December 2017. Gain on acquisition for the year ended 31 December 2016, related to the acquisition of Petroamerica.

3.9 Income Tax Expense and Recovery

(a) *Six months ended 30 June 2018 compared to six months ended 30 June 2017*

	Six Months Ended 30 June	
(Thousands of U.S. Dollars)	**2018**	**2017**
Income before income tax	$ 91,928	$ 38,057
Current income tax expense	$ 17,116	$ 9,189
Deferred income tax expense	36,651	22,904
Total income tax expense	$ 53,767	$ 32,093
Effective tax rate	58%	84%

Current income tax expense was higher in the six months ended 30 June 2018 compared with the corresponding period of 2017 as a result of higher taxable income in Colombia. The deferred income tax expense for the six months ended 30 June 2018 of $36.7 million was primarily due to excess tax depreciation as compared with accounting depreciation in Colombia.

For the six months ended 30 June 2018, the difference between the effective tax rate of 58% and the 21% U.S. statutory rate was primarily due to an increase to the impact of foreign taxes, valuation allowance, stock-based compensation, foreign currency translation and non-deductible third party royalty in Colombia.

For the six months ended 30 June 2017, the difference between the effective tax rate of 84% and the 35% U.S. statutory rate was primarily due to an increase in the impact of foreign taxes, other permanent differences, valuation allowance largely attributable to losses incurred in the United States and Colombia, as well as the impact of a non-deductible third-party royalty in Colombia, stock-based compensation and other local taxes.

(b) *Years ended 31 December 2017, 2016 and 2015*

	Year ended 31 December					
(Thousands of U.S. Dollars)		**2017**		**2016**		**2015**
Income (loss) before income tax	$	37,330	$	(650,234)	$	(368,088)
Current income tax expense	$	24,322		$20,122	$	15,383
Deferred income tax expense (recovery)		44,716		(204,791)		(115,442)
Total income tax expense (recovery)	$	69,038	$	(184,669)	$	(100,059)
Effective tax rate		185%		28%		27%
Deferred income tax recovery related to Colombia ceiling test impairment	$	—	$	201,300	$	91,700

Current income tax expense was higher in the year ended 31 December 2017, compared with 2016 and 2015 primarily as a result of higher taxable income in Colombia.

The deferred income tax expense for the year ended 31 December 2017 of $44.7 million was primarily a result of tax depreciation being higher than accounting depreciation in Colombia. In general, tax depreciation for capital expenditures investments incurred prior to 2017 is straight line over five years and accounting depreciation is based on the unit of production method. The deferred income tax recovery in the years ended 31 December 2016 and 2015 of $204.8 million and $115.4 million, respectively, were due to ceiling test impairment losses in Colombia. In 2016 and 2015, income tax recovery associated with impairment losses in Brazil and Peru was offset by a full valuation allowance.

The Group's effective tax rate was 185% for the year ended 31 December 2017, compared with 28% in 2016. The increase in the effective tax rate was primarily due to the increase in the impact of foreign taxes, mainly as a result of the difference between the tax rates in Colombia and US and applying this difference to a deferred tax expense during 2017 versus a deferred tax recovery during 2016; increase in the valuation allowance mainly due to $20.9 million of foreign tax credits in the US arising from the US legislated one-time deemed repatriation of foreign earnings; non-deductible third-party royalty in Colombia; and, stock based compensation. These were partially offset by decreases resulting from the sale of Brazil and Peru, other local taxes, and other permanent differences.

The Group's effective tax rate was 28% for the year ended 31 December 2016 compared with 27% in 2015. The increase in the effective tax rate was primarily due to a decrease in other permanent differences; non-deductible third party royalties; and, other local taxes. These were partially offset by an increase in the valuation allowance, the effect of foreign taxes, stock based compensation and foreign currency translation adjustments.

The difference between the Group's effective tax rate of 185% for the year ended 31 December 2017, and the 35% U.S. statutory rate was primarily due to due to an increase in the valuation allowance, mainly due to $20.9 million of foreign tax credits in the US arising from the US legislated one-time deemed repatriation of foreign earnings, $86.7 million of capital losses generated in Luxembourg as a result of the sale of Brazil, and $8.5 million of tax losses and tax credits generated in one of the entities in Colombia; the impact of foreign taxes, mainly due to the tax rate differential with Colombia; non-deductible third-party royalty in Colombia; stock based compensation; and, other local taxes. These were partially offset by decreases as a result of capital losses generated from the sale of Brazil, and other permanent differences.

The difference between the Group's effective tax rate of 28% for the year ended 31 December 2016, and the 35% U.S. statutory rate was primarily due to an increase in the valuation allowance; non-deductible third party royalties in Colombia; other local taxes, and, stock based compensation. These were partially offset by the impact of foreign taxes and other permanent differences.

3.10 Net Income and Funds Flow from Operations (a Non-GAAP Measure)

(a) *Six months ended 30 June 2018 compared to six months ended 30 June 2017*

(Thousands of U.S. Dollars)		Six Months Ended 30 June 2018 Compared with Six Months Ended 30 June 2017	% Change
Net income for the comparative period	$	5,964	
Increase (decrease) due to:			
Prices		95,920	
Sales volumes		14,967	
Expenses:			
Operating		(10,179)	
Transportation		(85)	
Cash G&A and RSU settlements, excluding stock-based compensation expense		1,012	
Interest, net of amortisation of debt issuance costs		(6,156)	
Realised foreign exchange		531	
Settlement of financial instruments		(16,699)	
Current taxes		(7,927)	
Equity tax		1,224	
Other		743	
Net change in funds flow from operations[(1)] from comparative period		73,351	
Expenses:			
Depletion, depreciation and accretion		(27,379)	
Deferred tax		(13,747)	
Amortisation of debt issuance costs		(288)	
Stock-based compensation, net of RSU settlement		(7,160)	
Financial instruments gain or loss, net of financial instruments settlements		(1,901)	
Unrealised foreign exchange		537	
Loss on sale		8,784	
Net change in net income		32,197	
Net income for the current period	**$**	**38,161**	**540%**

Note:

(1) Funds flow from operations is a non-GAAP measure which does not have any standardised meaning prescribed under U.S. GAAP. Please see above at paragraph 2.2 of this Part IV (*Operating and Financial Review*) for a definition and reconciliation of this measure.

(b) *Years ended 31 December 2017, 2016 and 2015*

(Thousands of U.S. Dollars)		Year ended 31 December 2017 compared with year ended 31 December 2016	% Change
Net loss for the comparative period	$	(465,565)	
Increase (decrease) due to:			
Sales volumes		32,161	
Prices		100,304	
Expenses:			
Operating		(22,944)	
Transportation		6,669	
Cash G&A and RSU settlements, excluding stock-based compensation expense		(1,690)	
Transaction		7,325	
Severance		32	

(Thousands of U.S. Dollars)		Year ended 31 December 2017 compared with year ended 31 December 2016	% Change
Interest, net of amortisation of debt issuance costs		(3,013)	
Realised foreign exchange		(1,270)	
Settlement of financial instruments		1,125	
Current taxes		(4,200)	
Equity tax		1,874	
Other		(1,160)	
Net change in funds flow from operations[(1)] from comparative period		115,213	
Expenses:			
Depletion, depreciation and accretion		8,200	
Asset impairment		615,135	
Deferred tax		(249,507)	
Amortisation of debt issuance costs		3,276	
Stock-based compensation, net of RSU settlement		(4,106)	
Financial instruments gain or loss, net of financial instruments settlements		(6,775)	
Unrealised foreign exchange		(2,265)	
Loss on sale		(45,314)	
Net change in loss		433,857	
Net loss for the current period	**$**	**(31,708)**	**93%**

Note:

(1) Funds flow from operations is a non-GAAP measure which does not have any standardised meaning prescribed under U.S. GAAP. Please see above at paragraph 2.2 of this Part IV (*Operating and Financial Review*)for a definition and reconciliation of this measure.

4. **2018 CAPITAL PROGRAM**

Colombia remains the Group's focus and represents 100% of the 2018 capital program. The Group has expanded the 2018 development capital program by an additional $15 to $30 million for:

- Ayombero appraisal drilling of 3 wells based on the success of the Ayombero-1 well;
- Costayaco development drilling in legacy reservoirs and 1 additional water injection well; and
- 2 Acordionero development wells accelerated from 2019 into fourth quarter 2018.

The Group expects the following ranges for its revised 2018 capital budget:

	Number of Wells (Gross)	Number of Wells (Net)		2018 Capital Budget ($million)
Colombia				
Development	22-24	21-22	$	130-135
Exploration	8-11	7-10		80-90
Facilities	—	—		75-80
Seismic and Studies	—	—		20
	30-35	28-32	$	305-325

Based on the midpoint of the guidance, the capital budget is forecasted to be approximately 68% directed to development and 32% to exploration. Between 35% and 40% of the revised 2018 development capital program is expected to be directed to facilities, with approximately 75% of this investment expected to be dedicated to the acceleration of the ongoing facilities expansion at the Acordionero Field. The Group expects its revised 2018 capital program to be fully funded by cash flows from operations.

Capital expenditures during the six months ended 30 June 2018, were $157.1 million:

(Thousands of U.S. Dollars)		
Colombia:		
Exploration	$	37,535
Development:		
Facilities		27,959
Drilling and Completions		77,194
Other		13,630
		156,318
Corporate		770
	$	157,088

During the six months ended 30 June 2018, the Group drilled the following wells in Colombia:

	Number of wells (Gross)	**Number of Wells (Net)**
Development	10	9.2
Exploration	2	0.5
Total Colombia	12	10.7

Ten development wells were spud, consisting of four in the Midas block (Acordionero-6, 22, 23-i and 24), four in the Chaza block (Costayaco-31, 32, 33 and 35-i), one in the Putumayo-7 block (Cumplidor-2), and the Suroriente block (Cohembi-16). Seven of these wells are currently on production (Acordionero-6, 22, Costayaco-31, 32, 33, 35-, and Cumplidor-2).

The Ayombero-1 well, which was in-progress at 31 December 2017, was brought on production during the first quarter of 2018. The Group spud an exploration well in the Midas block (Totumillo-1). These wells are targeting the conversion of prospective resources to reserves. The Group also drilled the Tonga-1 exploration well in the Sinu-3 block, which was plugged and abandoned as the well did not encounter commercial hydrocarbon quantities. This was a commitment exploration well.

The Group also continued facilities work at the Acordionero Field on the Midas block and the Moqueta and Costayaco Fields on the Chaza block. The Acordionero facilities expansion has been accelerated due to better than expected results to date and is designed to handle 30,000 bopd. During the six months ended 30 June 2018, the Group acquired additional working interests in Alea1848-A and 1947-C for total cash consideration of $3.1 million, which increased its position in these blocks to 100% and expanded the Group's exploration opportunities in the Putumayo basin. These acquisitions are subject to approval by the Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency).

5. CURRENT TRADING AND PROSPECTS

In the six months ended 30 June 2018, the Group achieved a new group milestone record Colombia WI production before royalties of 35,239 BOEPD, 20% higher compared with 29,294 BOEPD in the first half of 2017. Production increased largely because of production from development activities in the Acordionero Field. Since acquiring the Acordionero field in the MMV in August 2016, the Group has increased production 274% to a record high average rate during the second quarter of 17,710 bopd (14,076 bopd NAR). From the acquisition date of 23 August 2016 until 30 June 2018, the MMV assets have generated $327 million in oil and natural gas sales.

Oil and natural gas sales volumes in Colombia were 27,555 BOEPD, 13% higher than the first half of 2017. The increase in oil and gas sales volumes was driven by the production increase (5,945 bopd) , partially offset by higher royalties (2,202 bopd) due to higher oil prices and a change in inventories (569 bopd).

The Group continued to have significant exposure to oil price strength with oil representing 100% of production. Brent prices increased 35% from the first half of 2017. Oil and gas sales per BOE in Colombia were $60.49, 46% higher than the first half of 2017. Quality and transportation discount in Colombia was $10.55 per BOE compared with $11.46 per BOE in the first half of 2017; the reduction of $0.91 per BOE resulted from optimisation of transportation routes and narrowing of differentials.

Transportation expenses per BOE in Colombia were $2.71, 8% lower compared with the first half of 2017. The decrease was due to the increased use of alternative transportation routes, which had lower costs per BOE. Operating netback per BOE in Colombia was $45.48, 67% higher compared with the first half of 2017.

G&A expenses before stock-based compensation per BOE decreased by 11% to $2.92 per BOE compared with the first half of 2017.

The Group exited the first half of 2018 with $125.8 million of cash and cash equivalents.

6. LIQUIDITY AND CAPITAL RESOURCES

6.1 Overview

Gran Tierra believes that the Group's capital resources, including cash on hand, cash generated from operations and available capacity on its credit facility, will provide the Group with sufficient liquidity to meet its strategic objectives and planned capital program for 2018, given current oil price trends and production levels. In accordance with the Group's investment policy, available cash balances are held in its 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. The Group believes that its current financial position provides it the flexibility to respond to both internal growth opportunities and those available through acquisitions.

At 30 June 2018, the Group had a revolving credit facility with a syndicate of lenders with a borrowing base of $300 million and it had zero drawn on this credit facility. Availability under the revolving credit facility is determined by the reserves-based borrowing base determined by the lenders. The next re-determination of the borrowing base is due to occur no later than November 2018.

At 30 June 2018, the Group had $115 million aggregate principal amount of 5.00% Convertible Senior Notes due 2021 (the **"Convertible Notes"**) and $300 million aggregate principal amount of 6.25% Senior Notes due 2025 (the **"Senior Notes"**) outstanding. The Convertible Notes bear interest at a rate of 5.00% per year, payable semi-annually in arrears on 1 April and 1 October of each year. The Convertible Notes will mature on 1 April 2021, unless earlier redeemed, repurchased or converted.

The Convertible Notes are convertible to Common Stock at a conversion price of approximately $3.21 per share of Common Stock at the option of the holder at any time prior to the close of business on the business day immediately preceding the maturity date. The Senior Notes bear interest at a rate of 6.25% per year, payable semi-annually in arrears on 15 February and 15 August of each year, beginning on 15 August 2018. The Senior Notes will mature on 15 February 2025, unless earlier redeemed or repurchased.

Under the terms of the Revolving Credit Facility and Senior Notes, the Group is required to maintain compliance with certain financial and operating covenants which include: limitations on its ratio of debt to net income plus interest, taxes, depreciation, depletion, amortisation, exploration expenses and all non-cash charges minus all non-cash income (**"EBITDAX"**) to a maximum of 4.0 to 1.0 (under the credit facility) and 3.5 to 1.0 (under the Senior Notes); the maintenance of a ratio of EBITDAX to interest expense of at least 2.5 to 1.0 (definitions of debt, EBITDAX and other relevant terms are per the credit agreement or the indenture governing the Senior Notes and may differ between these agreements). As at 30 June 2018, the Group was in compliance with all financial and operating covenants in these agreements. Under the terms of the Revolving Credit Facility and Senior Notes, the Group is also limited in its ability to make distributions to Shareholders.

6.2 **Derivatives Positions**

As at 30 June 2018, the Group had outstanding commodity price derivative positions as follows:

Period and type of instrument	Volume, bopd	References	Sold Swap ($/bbl, Weighted Average)	Purchased Call ($/bbl, Weighted Average)
Swaps: 1 July 2018 to 31 December 2018	5,000	ICE Brent	$55.90	n/a
Participating Swaps: 1 July 2018 to 31 December 2018	5,000	ICE Brent	$52.50	$56.11

At 30 June 2018, current liabilities on the Group's balance sheet included $27.2 million in relation to the above outstanding commodity price derivative positions.

At 30 June 2018, the Group had the following outstanding foreign currency derivative positions:

Period and type of instrument	Amount Hedged (Millions COP)	U.S. Dollar Equivalent of Amount Hedged (Thousands of U.S. Dollars)[(1)]	Reference	Purchased Call (COP)	Sold Put (COP, Weighted Average)
Collars: 1 July 2018 to 31 December 2018	87,000	29,685	COP	3,000	3,107

Note:

(1) At 30 June 2018 foreign exchange rate.

At 30 June 2018, current assets on the Group's balance sheet included $0.9 million in relation to the above outstanding foreign currency derivative positions. The Group does not have any outstanding commodity price derivative positions relating to 2019.

6.3 **Cash Flows**

(a) The following table presents the Group's primary sources and uses of cash and cash equivalents for the six month periods ended 30 June 2017 and 2018.

	Six Months Ended 30 June	
	2018	2017
Sources of cash and cash equivalents:	$ 38,161	$ 5,964
Net income		
Adjustments to reconcile net income to EBITDA[(1)] and funds flow from operations[(1)]		
DD&A expenses	86,068	58,689
Interest expense	12,870	6,426
Income tax expense	53,767	32,093
EBITDA	190,866	103,172
Current income tax expense	(17,116)	(9,189)
Stock-based compensation expense	10,202	3,183
Contractual interest and other financing expenses	(11,357)	(5,201)
Cash settlement of RSUs	(360)	(501)
Unrealised foreign exchange loss	539	1,076
Financial instruments loss (gain)	11,714	(6,886)

	Six Months Ended 30 June	
	2018	2017
Cash settlement of financial instruments	(15,483)	1,216
Loss on sale	292	9,076
Funds flow from operations	169,297	95,946
Proceeds from bank debt, net of issuance costs	4,988	98,304
Proceeds from issuance of Senior Notes, net of issuance costs	288,087	—
Proceeds from issuance of shares	845	—
Cash deposit received for letter of credit arrangements upon sale of Brazil business unit	—	4,700
Deposit received for sale of Brazil business unit	—	34,481
	463,217	233,431
Uses of cash and cash equivalents:		
Additions to property, plant and equipment	(157,088)	(104,025)
Additions to property, plant and equipment - property acquisitions	(3,100)	(30,410)
Repayment of bank debt	(153,000)	(33,000)
Repurchase of shares of Common Stock	(1,208)	(10,000)
Net changes in assets and liabilities from operating activities	(37,994)	(28,112)
Changes in non-cash investing working capital	(6,142)	(627)
Settlement of asset retirement obligations	(369)	(298)
Foreign exchange loss on cash, cash equivalents and restricted cash and cash equivalents	(69)	(1,175)
	(358,970)	(207,647)
Net increase in cash and cash equivalents and restricted cash and cash equivalents	$ 104,247	$ 25,784

Note:

(1) EBITDA and funds flow from operations are a non-GAAP measures which do not have any standardised meaning prescribed under GAAP. Please see above at paragraph 2.2 of this Part IV (*Operating and Financial Review*) for a definition and reconciliation of this measure.

One of the primary sources of variability in the Group's cash flows from operating activities is the fluctuation in oil prices, the impact of which the Group partially mitigates by entering into commodity derivatives. Sales volume changes and costs related to operations and debt service also impact cash flow. The Group's cash flows from operating activities are also impacted by foreign currency exchange rate changes, the impact of which the Group partially mitigates by entering into foreign currency derivatives.

(b) The following table presents the Group's primary sources and uses of cash and cash equivalents for the year ended 31 December 2017, 2016 and 2015.

	Year ended 31 December		
	2017	2016	2015
Sources of cash and cash equivalents:	$ (31,708)	$ (465,565)	$ (268,029)
Net loss			
Adjustments to reconcile net loss to funds flow from operations[(1)]			
DD&A expenses	131,335	139,535	176,386
Asset impairment	1,514	616,649	323,918
Deferred tax expense (recovery)	44,716	(204,791)	(115,442)
Stock-based compensation expense	9,775	6,339	2,733
Amortisation of debt issuance costs	2,415	5,691	—
Cash settlement of RSUs	(564)	(1,234)	(1,392)
Unrealised foreign exchange loss	837	(1,428)	(8,380)
Financial instruments loss	15,929	10,279	2,027

	Year ended 31 December		
	2017	2016	2015
Cash settlement of financial instruments	1,563	438	(3,749)
Other gain	—	—	(502)
Loss on sale of business units and (gain) on acquisition	44,385	(929)	—
Funds flow from operations[(1)]	220,197	104,984	107,570
Proceeds from bank debt, net of issuance costs	167,043	256,065	—
Proceeds from issuance of Senior Notes, net of issuance costs			
Proceeds from issuance of shares			
Proceeds from oil and gas properties	—	6,000	—
Changes in non-cash investing working capital	19,680	21,116	—
Proceeds from sale of marketable securities	—	2,325	—
Net proceeds from sale of business units	32,968	—	—
Proceeds from issuance of Common Stock, net of issuance costs	—	128,273	722
Proceeds from issuance of subscription receipts, net of issuance costs	—	165,805	—
Proceeds from issuance of Convertible Notes, net of issuance costs	—	109,090	—
Foreign exchange gain on cash, cash equivalents and restricted cash and cash equivalents	—	354	—
	439,888	794,012	108,292
Uses of cash and cash equivalents:			
Acquisitions of PetroLatina and Petroamerica, net of cash acquired	—	(488,196)	—
Additions to property, plant and equipment - property acquisitions	(34,410)	(19,388)	—
Additions to property, plant and equipment, excluding PGC acquisition	(251,041)	(127,789)	(156,639)
Repayment of debt	(110,000)	(252,181)	—
Cash paid for investments	(11,000)	—	—
Changes in non-cash investing working capital	—	—	(76,844)
Changes in non-cash operating working capital	(29,217)	(11,337)	(39,048)
Cash settlement of asset retirement obligation	(1,336)	(605)	(6,217)
Repurchase of shares of Common Stock	(17,916)	—	(9,999)
Foreign exchange loss on cash, cash equivalents and restricted cash and cash equivalents	(1,557)	—	(6,516)
	(456,477)	(899,496)	(295,263)
Net increase in cash and cash equivalents and restricted cash and cash equivalents	$ (16,589)	$ (105,484)	$ (186,971)

Note:

(1) Funds flow from operations are a non-GAAP measures which do not have any standardised meaning prescribed under GAAP. Please see above at paragraph 2.2 of this Part IV (*Operating and Financial Review*) for a definition and reconciliation of this measure.

Cash provided by operating activities in the year ended 31 December 2017, was primarily affected by higher funds flow from operations (see funds flow from operations reconciliation above) and a $29.2 million change in assets and liabilities from operating activities.

One of the primary sources of variability in the Group's cash flows from operating activities is the fluctuation in oil prices, the impact of which the Group partially mitigates by entering into commodity derivatives. Sales volume changes and costs related to operations and debt service also impact cash flow. The Group's cash flows from operating activities are also impacted by foreign currency exchange rate changes, the impact of which it partially mitigates by entering into foreign currency derivatives.

6.4 Contractual obligations

During February 2018, the Group issued $300 million aggregate principal amount of the Senior Notes. During the six months ended 30 June 2018, the Group fully repaid the balance of $153 million outstanding under its Revolving Credit Facility, which remained undrawn at 30 June 2018.

Except as noted above, as at 30 June 2018, there were no other material changes to the Group's contractual obligations outside of the ordinary course of business from those as at 31 December 2017.

The following is a schedule by year of purchase obligations, future minimum payments for firm agreements and leases that have initial or remaining non-cancellable terms in excess of one year as of 31 December 2017:

	Total	**2018**	**2019-2020**	**2021-2022**	**2022 and beyond**
(Thousands of U.S. Dollars)					
Revolving credit facility	$148,000	$—	$148,000	$—	$—
5% Convertible Senior Notes due 2021	115,000	—	—	115,000	—
Total long-term debt	263,000	—	148,000	115,000	—
Interest payments[1]	34,116	11,144	21,534	1,438	—
Oil transportation services	10,895	3,842	7,053	—	—
Facility construction	27,006	5,446	10,907	10,653	—
Operating leases	4,554	1,840	2,507	207	—
Software and telecommunication	961	339	622	—	—
Total	$340,532	$22,611	$190,623	$127,298	—

Note:

(1) Interest payments have been calculated utilising the rates associated with the Convertible Notes outstanding at 31 December 2017. Interest payments on the Revolving Credit Facility were calculated by assuming that the 31 December 2017, outstanding balance of $148.0 million will be outstanding through the November 2020 maturity date and that the Convertible Notes will remain outstanding through their April 2021 maturity date. A constant interest rate of 3.64% was assumed for the interest payments on the Revolving Credit Facility, which was the 31 December 2017 weighted-average interest rate. Actual results will differ from these estimates and assumptions.

During February 2018, the Group issued $300 million aggregate principal amount of the Senior Notes. Please see Note 5 (*Debt and Debt Issuance Costs*) to the Group's condensed consolidated financial statements for the six months ended 30 June 2018 in Appendix 1 (*Historical Financial Information*) for further information. During the six months ended 30 June 2018, the Group fully repaid the balance of $153 million outstanding under its Revolving Credit Facility, which remained undrawn at 30 June 2018. Except as noted above, as at 30 June 2018, there were no other material changes to the Group's contractual obligations outside of the ordinary course of business from those as at 31 December 2017.

At 31 December 2017, the Group had provided promissory notes totalling $76.0 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 utilise the Group's revolving credit facility capacity because they are backed by local Colombian banks or insurance companies.

The above table does not reflect estimated amounts expected to be incurred in the future associated with the abandonment of the Group's oil and gas properties and other long-term liabilities, as the Group cannot determine with accuracy the timing of such payments.

Information regarding the Group's asset retirement obligation can be found in Note 8 (*Asset Retirement Obligation*) to the Group's consolidated financial statements for the financial year ended 31 December 2017 in Appendix 1 (*Historical Financial Information*).

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

6.5 Off-balance sheet arrangements

As at 30 June 2018, the Group had no off-balance sheet arrangements.

7. CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

On a regular basis the Group evaluates its estimates, judgments and assumptions. The Group also discuss its 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.

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

The Group follows the full cost method of accounting for its oil and natural gas properties in accordance with SEC Regulation S-X Rule 4-10, as described in Note 2 (*Significant Accounting Policies*) to the Group's consolidated financial statements for the financial year ended 31 December 2017 in Appendix 1 (*Historical Financial Information*). Under the full cost method of accounting, all costs incurred in the acquisition, exploration and development of properties are capitalised, including internal costs directly attributable to these activities. The sum of net capitalised 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 the Group's 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 the Group has 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.

The Group's estimates of proved oil and gas reserves are a major component of the depletion and full cost ceiling calculations. Additionally, the Group's 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.

The Group believes its assumptions are reasonable based on the information available at the time the estimates were prepared. However, these estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change.

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

While the quantities of proved reserves require substantial judgment, the associated prices of oil and natural gas and the applicable discount rate, that are used to calculate the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that a 10% discount factor be used and future net revenues are calculated using prices that represent the average of the first day of each month price for the 12-month period. Therefore, the future net revenues associated with the estimated proved reserves are not based on the Group's assessment of future prices or costs, but reflect adjustments for gravity, quality, local conditions, gathering and transportation fees and distance from market. Estimates of standardised measure of the Group's future cash flows from proved reserves for the Group's 31 December 2017 ceiling tests were based on wellhead prices per BOE as of the first day of each month within that twelve month period of $43.00 for Colombia. 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 the Group's properties. Historical oil and gas prices for any particular 12-month period can be either higher or lower than the Group's 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.

Gran Tierra's Reserves Committee oversees the annual review of the Group's 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.

In the year ended 31 December 2017, the Group had no ceiling test impairment losses in its Colombia and Brazil cost centres. The Group used an average Brent price of $54.19 per bbl for the purposes of the 31 December 2017 ceiling test calculations (30 September 2017 - 52.70, 30 June 2017 - $51.35, 31 March 2017 - $49.33; 31 December 2016 - $42.92; 30 September 2016 - $42.23; 30 June 2016 - $44.48, 31 March 2016 - $48.79; 31 December 2015 - $54.08).

In the year ended 31 December 2016, the Group recorded ceiling test impairment losses of $513.7 million in its Colombia cost centre, and $71.1 million in its Brazil cost centre. The Colombia ceiling test impairment loss related to lower oil prices and the fact that the acquisitions of PetroLatina and Petroamerica were initially added into the cost base at estimated fair value.

However, these acquired assets were subjected to a prescribed U.S. GAAP ceiling test, which is not a fair value test, and which, uses constant commodity pricing that averages prices during the preceding 12 months. The Brazil ceiling test impairment loss related to continued low oil prices and increased costs in the depletable base as a result of a $45.0 million impairment of unproved properties. In the year ended 31 December 2015, the Group recorded ceiling test impairment losses of $232.4 million in its Colombia cost centre, and $46.9 million in its Brazil cost centre as a result of lower realised prices.

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.

Subject to these factors and inherent limitations and holding all factors constant other than benchmark oil prices, the Group does not believe that ceiling test impairment losses will be experienced in the third quarter of 2018. The calculation of the impact of higher commodity prices on the Group's estimated ceiling test calculation was prepared based on the presumption that all other inputs and assumptions are held constant with the exception of benchmark oil prices. Therefore, this calculation strictly isolates the impact of commodity prices on the prescribed U.S. GAAP ceiling test. This calculation was based on pro forma Brent oil price of $57.74 per bbl for the 12 months ended 31 March 2018. This pro forma oil price was calculated using a 12-month unweighted arithmetic average of oil prices, and included the oil prices on the first day of the month for the eleven months ended February 2018, and, for the month ended March 2018, estimated oil prices for the first quarter of 2018 using the forward price curve forecast from Bloomberg dated 31 December 2017. As noted above, actual cash flows may be materially affected by other factors. For example, in Colombia, cash royalties are levied at lower rates in low oil price environments and foreign exchange rates can materially impact the deferred tax component of the asset base, operating costs, and the income tax calculation.

Holding all factors constant other than benchmark oil prices and related royalty rates, the Group does not expect any downward adjustment to the Group's consolidated NAR reserve volumes during the third quarter of 2018. This disclosure is based on a pro forma Brent oil price of $57.74 per bbl for the 12 months ended 31 March 2018, calculated as described above.

7.2 **Unproved properties**

Unproved properties are not depleted pending the determination of the existence of proved reserves. Costs are transferred into the amortisation 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 amortisation. The transfer of costs into the amortisation base involves a significant amount of judgment and may be subject to changes over time based on the Group's 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.

7.3 **Asset Retirement Obligations**

The Group is required to remove or remedy the effect of its activities on the environment at the Group's present and former operating sites by dismantling and removing production facilities and remediating any damage caused. Estimating the Group's future ARO requires it 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 the Group operates.

The Group records ARO in its consolidated financial statements by discounting the present value of the estimated retirement obligations associated with the Group's oil and gas wells and facilities. In arriving at amounts recorded, the Group makes 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, the Group must recognise 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 capitalised 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 the Group's assumptions. As a result, the Group is unable to provide a reasonable sensitivity analysis of the impact a change in its assumptions would have on its financial results.

7.4 **Equity Method Investment**

During December 2017, the Group acquired an investment in common shares of PetroTal in connection with the sale of the Group's Peru business unit. At 31 December 2017, this investment represented approximately 46% of PetroTal's issued and outstanding common shares. The Group determined that it did not have a controlling financial interest in PetroTal, but could exert significant influence over PetroTal's operating and financial policies as a result of the Group's ownership interest in PetroTal and the right to nominate two directors to PetroTal's board of directors. Accordingly, the Group accounted for its investment in the common shares of PetroTal as an equity method investment, but elected the fair value option for this investment.

The fair value of the current portion of the investment was estimated using quoted market prices in active markets. The long-term portion of the investment was estimated based on quoted market prices and valuation technique using observable and one or more unobservable inputs. Information regarding the valuation of the investment can be found in Note 12 (*Financial Instruments, Fair Value Measurement, Credit Risk and Foreign Exchange Risk*) to the Group's consolidated financial statements for the financial year ended 31 December 2017 in Appendix 1 (*Historical Financial Information*).

7.5 **Goodwill**

Goodwill represents the excess of the aggregate of the consideration transferred over net identifiable assets acquired and liabilities assumed. The goodwill on the Group's balance sheet relates entirely to its Colombia reporting unit.

At each reporting date, the Group assesses qualitative factors to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount and whether it is necessary to perform the goodwill impairment test. Changes in the Group's future cash flows, operating results, growth rates, capital expenditures, cost of capital, discount rates, stock price or related market capitalisation, could affect the results of the Group's annual goodwill assessment and, accordingly, potentially lead to future goodwill impairment charges. The goodwill impairment test would require a comparison of the fair value of the reporting unit to its net book value If the estimated fair value of the reporting unit were less than its net book value, including goodwill, the Group would recognise the goodwill impairment in an amount not exceeding the carrying amount of goodwill through a charge to expense.

The most significant judgments involved in estimating the fair value of the Group's reporting unit would relate to the valuation of the Group's property and equipment. Unfavourable changes in reserves or in the Group's price forecast would increase the likelihood of a goodwill impairment charge. A goodwill impairment charge would have no effect on liquidity or capital resources. However, it would adversely affect the Group's results of operations in that period. At 31 December 2017, the Group performed a qualitative assessment of goodwill and, based on this assessment, no impairment of goodwill was identified. Forward curve oil prices as at 31 December 2017, were higher than those used in the ceiling test impairment calculation. Increased reserves and forward curve oil prices as at 31 December 2017, resulted in no impairment of goodwill.

7.6 **Income Taxes**

The Group follows the liability method of accounting for income taxes whereby the Group recognises 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 recognised for the future tax benefits attributable to the expected utilisation 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 recognised in income in the period that includes the enactment date.

The Group carries on business in several countries and as a result, it is subject to income taxes in numerous jurisdictions. The determination of the Group's income tax provision is inherently complex and the Group is required to interpret continually changing regulations and make certain judgments. While income tax filings are subject to audits and reassessments, the Company believes it has 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 the Group's provision for income taxes.

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

The Group's effective tax rate is based on pre-tax income and the tax rates applicable to that income in the various jurisdictions in which it operates. An estimated effective tax rate for the year is applied to the Group's quarterly operating results. In the event that there is a significant unusual or discrete item recognised, or expected to be recognised, in the Group's 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. The Group considers the resolution of prior-year tax matters to be such items. Significant judgment is required in determining the Group's effective tax rate and in evaluating the Group's tax positions. The Group establishes reserves when it is more likely than not that it will not realise the full tax benefit of the position. The Group adjusts these reserves in light of changing facts and circumstances.

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

7.7 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 the Group should record losses for these items based on information available to the Group.

7.8 Stock-Based Compensation

The Group's 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-Merton 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. The Group uses historical data to estimate the expected term used in the Black-Scholes option pricing model, option exercises and employee departure behaviour. Expected volatilities used in the fair value estimate are based on the historical volatility of Gran Tierra'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.

7.9 New Accounting Pronouncements

The Group adopted Accounting Standard Codification (**"ASC"**) 606 *Revenue from Contracts with Customers* with a date of initial application of 1 January 2018 in accordance with the modified retrospective method. Adoption of the ASU did not have a material impact on its consolidated financial statements, other than enhanced disclosure related to revenues from contracts with customers.

In January 2016, the FASB issued ASU 2016-01, "Recognition and Measurement of Financial Assets and Financial Liabilities". ASU 2016-01 addressed certain aspects of recognition, measurement, presentation and disclosure of financial instruments. ASU 2016-01 was effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after 15 December 2017. The implementation of this update did not impact on the Company's consolidated financial position, results of operations or cash flows or disclosure.

In February 2018, the FASB issued ASU 2018-03, "Recognition and Measurement of Financial Assets and Financial Liabilities". ASU 2018-03 clarified certain aspects of the guidance in ASU 2016-01. ASU 2018-03 is effective for annual reporting periods beginning after 15 December 2017 and interim reporting periods within those annual reporting periods beginning after 15 June 2018. Early adoption is permitted upon adoption of ASU 2016-01. The amendments should be applied retrospectively with a cumulative-effect adjustment to the effective date of ASU 2016-01. The Company early adopted this update on January 1, 2018. The implementation of this update did not impact the Company's consolidated financial position, results of operations or cash flows or disclosure.

In February 2016, the FASB issued ASU 2016-02, "Leases". This ASU will require most lease assets and lease liabilities to be recognised on the balance sheet and the disclosure of key information about lease arrangements. The ASU will be effective for fiscal years, beginning after 15 December 2018. In January 2018, the FASB issued ASU 2018-01, "Land Easement Practical Expedient for Transition to Topic 842". ASU 2018-01 provides an optional transition practical expedient that, if elected, would not require an organisation to reconsider their accounting for existing or expired land easements that were not previously accounted for as leases under Topic 840. The effective date and transition requirements for the amendment is the same as the effective date and transition requirements in Update 2016-02. The Company is planning to adopt ASU 2018-01 upon transition to ASU 2016-02 "Leases".

The Company is finalising an assessment of its contract inventory using certain practical expedients to determine which contracts meet the definition of a lease. The next steps will include classifying leases as either financing or operating, establishing interest rates and determining the value of right-of-use lease assets and lease liabilities. The Company expects to apply the guidance of ASU 2016-02 using a modified retrospective transition approach.

In June 2016, the FASB issued ASU 2016-13, "Financial Instruments - Credit Losses". This ASU replaces the current incurred loss impairment methodology with a methodology that reflects expected credit losses and requires a broader range of reasonable and supportable information to support credit loss estimates. The ASU will be effective for fiscal years, and interim periods within those years, beginning after 15 December 2019. The Group is currently assessing the impact this update will have on its consolidated financial position, results of operations, cash flows, and disclosure.

8. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

Gran Tierra's activities expose it to a variety of market risks, including commodity price risk, foreign currency risk and interest rate risk. Gran Tierra's senior management team oversees the management of these risks and has established policies and procedures to govern the Group's financial risk taking to help ensure that financial risks are identified, measured and managed in accordance with the Group's policies and risk appetite. The Board reviews and agrees the policies for managing each of these risks, which are summarised below.

8.1 Commodity price risk

The Group's 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 the control of the Group. Most of the Group's revenues are from oil sales at prices which reflect the blended prices received upon shipment by the purchaser at defined sales points or are defined by contract relative to West Texas Intermediate (**"WTI"**) or Brent and adjusted for quality each month.

During the year ended 31 December 2017, the Group entered into commodity price derivative contracts to manage the variability 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 the Group can execute at least a portion of its capital spending. The table below provides information about the Group's commodity price derivative contracts at 30 June 2018, including the notional amounts and weighted average exchange rates by expected (contractual) maturity dates. Expected cash flows from the forward contract equalled the fair value of the contract. The information is presented in U.S. dollars because that is the reporting currency of the Group. Gran Tierra does not hold any of these investments for trading purposes.

Period and type of instrument	**Volume, bopd**	**References**	**Sold Swap ($/bbl, Weighted Average)**	**Purchased Call ($/bbl, Weighted Average)**
Swaps: July 1, to 31 December 2018	5,000	ICE Brent	$55.90	n/a
Participating Swaps: July 1, to 31 December 2018	5,000	ICE Brent	$52.50	$56.11

8.2 **Foreign currency risk**

Foreign currency risk is a factor for the Group but is ameliorated to a certain degree by the nature of expenditures and revenues in the countries where it operates. The Group's reporting currency is U.S. dollars and 100% of the Group's revenues are related to the U.S. dollar price of Brent or WTI oil. In Colombia, Gran Tierra receives 100% of the Group's revenues in U.S. dollars and the majority of the Group's capital expenditures are in U.S. dollars or are based on U.S. dollar prices. Many of the operational expenses, and a portion of capital expenditures, incurred by the Group are denominated in Colombian pesos. The majority of income and value added taxes and G&A expenses in all locations are in local currency. While the Group operates in South America exclusively, the majority of its acquisition expenditures have been valued and paid in U.S. dollars.

Additionally, foreign exchange gains and losses result primarily from the fluctuation of the U.S. dollar to the Colombian peso due to the Group's current and deferred tax liabilities, which are monetary liabilities, denominated in the local currency of the Colombian foreign operations. As a result, a foreign exchange gain or loss must be calculated on conversion to the U.S. dollar functional currency. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $10,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

During the year ended 31 December 2017, the Group entered into foreign currency derivative contracts to manage the variability in cash flows associated with the Group's forecasted Colombian peso denominated costs. The table below provides information about the Group's foreign currency forward exchange agreements at 30 June 2018, including the notional amounts and weighted average exchange rates by expected (contractual) maturity dates. Expected cash flows from the forward contract equalled the fair value of the contract. The information is presented in U.S. dollars because that is the reporting currency of the Group. The Group does not hold any of these investments for trading purposes.

Period and type of instrument	Amount Hedged (Millions COP)	U.S. Dollar Equivalent of Amount Hedged (Thousands of U.S. Dollars)[(1)]	Reference	Purchased Call (COP)	Sold Put (COP, Weighted Average)
Collars: 1 July 2018 to 31 December 2018	87,000	29,685	COP	3,000	3,107

8.3 **Interest rate risk**

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. Gran Tierra is exposed to interest rate fluctuations on the Revolving Credit Facility, which bears floating rates of interest. At 30 June 2018, there were no outstanding amounts under the Revolving Credit Facility (31 December 2017 - $148.0 million).

The Group's investment objectives are focused on preservation of principal and liquidity. By policy, the Group manages its 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 the Group's investment portfolio. The Group does not hold any of these investments for trading purposes.

PART V – CAPITALISATION AND INDEBTEDNESS

The tables below set out the Group's unaudited capitalisation and indebtedness as at 30 June 2018 and its unaudited net current financial indebtedness and non-current financial indebtedness as at 30 June 2018. The capitalisation and indebtedness figures as at 30 June 2018 have been extracted without material adjustment from the Group's historical financial information set out in Appendix 1 (*Historical Financial Information*).

1. CAPITALISATION AND INDEBTEDNESS

The table below sets out the Company's total capitalisation and indebtedness as at 30 June 2018.

	As at
	30 June 2018
	$(*thousands, unaudited*)
Current debt	
Guaranteed	-
Secured	-
Unguaranteed/unsecured	-
Total current debt	-
Non-current debt	
Guaranteed	-
Secured	-
Unguaranteed/unsecured	415,000
Total non-current debt	415,000
Capitalisation	
Share capital	10,295
Share premium	1,328,037
Legal reserve	-
Other reserves	(363,043)
Total capitalisation	975,289
Total capitalisation and indebtedness	1,390,289

There has not been any material change in the Company's total capitalisation and indebtedness since 30 June 2018.

2. NET FINANCIAL INDEBTEDNESS

The table below sets out the Company's total net current financial indebtedness and non-current financial indebtedness as at 30 June 2018.

	As at 30 June 2018
	$(*thousands, unaudited*)
Cash	125,807
Cash equivalents	-
Trading securities	21,320
Liquidity	147,127
Current bank debt	-
Current portion of non-current debt	-
Other current financial debt	-
Current financial debt	-
Net current financial indebtedness	147,127
Non-current bank loans	-
Bonds issued	415,000
Other non-current loans	-
Non-current financial indebtedness	415,000
Net financial indebtedness	(267,873)

The Company has no other indirect or contingent liabilities, or any contingent commitments.

PART VI – TAXATION

The statements on taxation referred to in this Part VI of the Prospectus are for general information purposes only and are not intended to be a comprehensive summary of all technical aspects of the structure and are not intended to constitute legal or tax advice to potential investors.

The statements on taxation below are intended to be a general summary of certain tax consequences that may arise for prospective investors in relation to the Common Stock (which may vary depending upon the particular individual circumstances and status of prospective investors), and a general guide to the tax treatment of the Company. These comments are based on the laws and practices as at the time of writing and may be subject to future revision. This discussion is not intended to constitute advice to any person and should not be so construed.

1. UNITED KINGDOM

1.1 General

The following statements are intended to apply only as a general guide to certain UK tax considerations, and are based on current UK tax law and what is understood to be the current practice of HM Revenue and Customs (**"HMRC"**) as at the date of this Prospectus, both of which are subject to change at any time, possibly with retrospective effect. They relate only to certain limited aspects of the UK taxation treatment of Shareholders who are resident and, in the case of individuals, domiciled in (and only in) the UK for UK tax purposes (except to the extent that the position of non-UK resident Shareholders is expressly referred to), who hold the Common Stock as an investment (other than under an individual savings account or a self-invested personal pension) and who are the beneficial owners of both the Common Stock and any dividends paid on them.

The statements may not apply to certain categories of Shareholders such as (but not limited to) persons acquiring their Common Stock in connection with an office or employment, dealers in securities, insurance companies and collective investment schemes.

Prospective purchasers of Common Stock who are in any doubt as to their tax position regarding the acquisition, ownership and disposition of the Common Stock or who are subject to tax in a jurisdiction other than the United Kingdom are strongly recommended to consult their own tax advisers.

For the purposes of UK taxation (other than stamp duty and stamp duty reserve tax) holders of CDIs or Depositary Interests should generally be treated as holders of the Common Stock represented by such securities, and references to Shareholders below include references to holders of such CDIs or Depositary Interests (except in relation to stamp duty and SDRT).

1.2 Dividends on the Common Stock

(a) UK resident individuals

All dividends received by a Shareholder who is a UK resident individual in respect of the Common Stock will form part of that Shareholder's total income for income tax purposes, subject to any available allowances and reliefs.

A nil rate of tax will apply for the first £2,000 of dividend income in any tax year (the **"nil rate band"**) and different rates of tax will apply for dividend income that (taking account of any other dividend income received by the Shareholder in the same tax year) exceeds the nil rate band.

The rates are 7.5 per cent. to the extent that it falls within the basic tax rate band; 32.5 per cent. to the extent that it is within the higher rate band; or 38.1 per cent. to the extent that it is within the additional rate band.

For these purposes "dividend income" includes UK and non UK source dividends and certain other distributions in respect of shares.

For the purposes of determining which of the taxable bands dividend income falls into, dividend income is treated as the highest part of a Shareholder's income. In addition, dividends within the nil rate band which would otherwise have fallen within the basic or higher rate bands will use up those bands respectively and so will be taken into account in determining whether the threshold for higher rate or additional rate income tax is exceeded.

(b) UK resident companies

Shareholders within the charge to UK corporation tax which are "small companies" for the purposes of Chapter 2 of Part 9A of the Corporation Tax Act 2009 will not be subject to UK corporation tax on any dividend received from the Company provided certain conditions are met (including an anti-avoidance condition). Such companies are not entitled to tax credits on any dividends paid by the Company.

Other Shareholders within the charge to UK corporation tax will not be subject to UK corporation tax on dividends received from the Company so long as the dividends fall within an exempt class and certain other conditions are met. Examples of exempt classes include dividends paid on shares that are "ordinary shares" and are not "redeemable" (as defined in Chapter 4 of Part 9A of the Corporation Tax Act 2009), and dividends paid to a person holding less than a 10 per cent. interest in the Company. However, the exemptions are not comprehensive and are subject to anti-avoidance rules.

If the conditions for exemption are not met or cease to be satisfied, or such a Shareholder elects for an otherwise exempt dividend to be taxable, the Shareholder will be subject to UK corporation tax on dividends received from the Company at the rate of corporation tax applicable to that Shareholder (currently 19 per cent. for companies paying the full rate of corporation tax (set to reduce to 17 per cent. from 1 April 2020)).

(c) Non-UK resident Shareholders

Where a Shareholder who is resident for tax purposes outside the UK carries on a trade profession or vocation in the UK and the dividends are a receipt of that trade, profession or vocation or, in the case of corporation tax, the Common Stock is held for a UK permanent establishment through which a trade is carried on, the Shareholder may be liable to UK tax on dividends paid by the Company.

A Shareholder resident outside the UK may be subject to taxation on dividend income under their local law. Any such Shareholder should consult their own tax advisers concerning their tax liabilities (in the UK and any other country) on dividends received from the Company and whether any double taxation relief is due in any country in which they are subject to tax.

(d) Withholding taxes

The Company is not required to withhold UK tax at source from dividend payments or any other distributions it makes to Shareholders in respect of the Common Stock.

1.3 **Taxation of disposals**

(a) General

A disposal or deemed disposal of Common Stock by a Shareholder who is (at any time in the relevant UK tax year) resident in the UK for tax purposes may give rise to a chargeable gain or an allowable loss for the purposes of UK taxation of chargeable gains depending upon the Shareholder's circumstances and subject to any available exemption or relief.

(b) UK resident individual Shareholders

For an individual Shareholder within the charge to UK capital gains tax, a disposal (or deemed disposal) of Common Stock may give rise to a chargeable gain or an allowable loss for the purposes of capital gains tax. The rate of capital gains tax is 10 per cent. for individuals who are subject to income tax at the basic rate and 20 per cent. for individuals who are subject to income tax at the higher or additional rates. An individual Shareholder is entitled to realise an annual exempt amount of gains (currently £11,700) for the year 6 April 2018 to 5 April 2019 without being liable to tax.

(c) UK resident corporate Shareholders

For a corporate Shareholder within the charge to UK corporation tax, a disposal (or deemed disposal) of Common Stock may give rise to a chargeable gain or an allowable loss for the purposes of UK corporation tax. Corporation tax is charged on chargeable gains at the rate applicable to the relevant company (currently 19 per cent. for companies paying the full rate of corporation tax (set to reduce to 17 per cent. from 1 April 2020)).

(d) Non-UK resident Shareholders

A Shareholder (individual or corporate) who is not resident in the UK for tax purposes is generally not subject to UK taxation on chargeable gains. They may, however, be subject to taxation under their local law.

However, if such a Shareholder carries on a trade, profession or vocation in the UK through a branch or agency (or, in the case of a non-UK resident corporate Shareholder, a permanent establishment) to which their holding of Common Stock is attributable, the Shareholder will be subject to the same rules that apply to UK resident Shareholders.

Generally, an individual Shareholder who acquires Common Stock whilst UK resident and who subsequently ceases to be resident for tax purposes in the UK only temporarily (i.e., less than five complete UK tax years) and who disposes of the Common Stock during that period of non-residence may be liable, on their return to the UK, to capital gains tax in respect of any gain arising from the disposal (subject to any available exemption or relief). Special rules apply to Shareholders who are subject to tax on a "split-year" basis, who should seek specific professional advice if they are in any doubt about their position.

1.4 Stamp duty and stamp duty reserve tax

Admission of the Common Stock to the standard listing segment of the Official List will not give rise to a liability to stamp duty or SDRT.

No SDRT will be chargeable on any agreement to transfer CDIs or Depositary Interests so long as it continues to be the case that (i) the Common Stock are listed on a recognised stock exchange (both the Official List of the London Stock Exchange and the Toronto Stock Exchange are listed by HMRC as recognised stock exchanges), (ii) those interests can only be transferred through the CREST system, (iii) the central management and control of the Company is exercised outside the UK and (iv) the shareholders' register is maintained outside the UK.

No SDRT will be chargeable on any agreement to transfer the Common Stock itself so long as the shareholders' register continues to be maintained outside the UK.

Stamp duty could in certain circumstances be payable if title to Common Stock were transferred by written instrument, for stampable consideration greater than £1,000. If the instrument were executed in the UK or related to any matter or thing done in the UK, a party wishing to rely on the instrument in civil proceedings in the UK would have to submit it to HM Revenue & Customs for stamping (at 0.5% of the consideration, rounded to the nearest £5).

2. CERTAIN UNITED STATES TAX CONSIDERATIONS

2.1 General

The following is a summary of U.S. federal income tax considerations generally applicable to Non-U.S. Holders (as defined below) with respect to the ownership and disposition of the Common Stock and is based upon the United States Internal Revenue Code of 1986 (the **"IRS Code"**), the Treasury Department regulations promulgated thereunder (**"Regulations"**), and administrative and judicial interpretations thereof, all as of the date hereof and all of which are subject to change, possibly with retroactive effect. This discussion is limited to non-U.S. Holders who hold the Common Stock as capital assets within the meaning of Section 1221 of the IRS Code. No ruling has been or is expected to be sought from the IRS with respect to any of the tax considerations discussed below. As a result, there can be no assurances that the IRS will agree with the views expressed in this discussion or that a court will not sustain any challenge by the IRS in the event of litigation.

Moreover, this discussion does not address all of the tax considerations that may be relevant to Non-U.S. Holders in light of their particular circumstances, nor does it discuss special tax provisions, which may apply to holders subject to special treatment under U.S. federal income tax laws, such as certain financial institutions or financial services entities, insurance companies, tax-exempt entities, dealers in securities, entities that are treated as partnerships for U.S. federal income tax purposes, "controlled foreign corporations," "passive foreign investment companies," former U.S. citizens or long-term residents, persons deemed to sell the Common Stock under the constructive sale provisions of the IRS Code, and persons that hold the Common Stock as part of a straddle, conversion transaction, or other integrated investment. Furthermore, this discussion does not address any tax considerations arising under the Medicare contribution tax or the alternative minimum tax, nor does it address any tax considerations arising under the laws of any state, local or foreign jurisdiction, or under any U.S. federal laws other than those pertaining to income or estate taxes.

2.2 **Non-U.S. Holder**

As used in this discussion, the term **"Non-U.S. Holder"** means a beneficial owner of the Common Stock that is not an entity or arrangement treated as a partnership for U.S. federal income tax purposes and is not, for U.S. federal income tax purposes:

- an individual who is a citizen or resident of the U.S.;
- a corporation (or other entity taxable as a corporation for U.S. federal income tax purposes) that is created or organised in or under the laws of the U.S., any state thereof or the District of Columbia;
- an estate the income of which is subject to U.S. federal income taxation regardless of its source; or
- a trust if (i) a court within the U.S. is able to exercise primary supervision over the administration of the trust and one or more U.S. persons (as defined in the IRS Code) have the authority to control all substantial decisions of the trust or (ii) it has a valid election in effect under applicable Regulations to be treated as a domestic trust for U.S. federal income tax purposes.

If a partnership (or any entity or arrangement treated as a partnership for U.S. federal income tax purposes) is a beneficial owner of the Common Stock, the tax treatment of a partner in the partnership will generally depend upon the status of the partner, the activities of the partnership and certain determinations made at the partner level. A beneficial owner that is a partnership, and the partners in such partnership, should consult their tax advisors regarding the tax considerations of the ownership and disposition of the Common Stock.

NON-U.S. HOLDERS ARE ADVISED TO CONSULT THEIR TAX ADVISORS WITH RESPECT TO CURRENT AND POSSIBLE FUTURE TAX CONSIDERATIONS OF OWNING AND DISPOSING OF THE COMMON STOCK, AS WELL AS ANY TAX CONSIDERATIONS THAT MAY ARISE UNDER THE LAWS OF ANY U.S. STATE, LOCAL OR OTHER TAXING JURISDICTION, IN LIGHT OF THEIR PARTICULAR CIRCUMSTANCES.

2.3 **Dividends**

As discussed above, the Company does not have a current plan to make any distributions on the Company's equity, including the Common Stock. If distributions are paid on the Common Stock, such distributions will constitute dividends for U.S. federal income tax purposes to the extent paid from the Company's current or accumulated earnings and profits, as determined under U.S. federal income tax principles. If a distribution exceeds the Company's current and accumulated earnings and profits, such excess will constitute a return of capital that reduces, but not below zero, a Non-U.S. Holder's tax basis in the Common Stock. Any remainder will constitute gain from the sale or exchange of the Common Stock, subject to the tax treatment described below under paragraph 2.4 of this Part VI (*Taxation*). Except as provided in the following paragraph, if dividends are paid, Non-U.S. Holders are generally subject to withholding of U.S. federal income tax at a 30% rate, or a lower rate as may be specified by an applicable income tax treaty, on the gross amount of the dividends paid to such holders. To claim the benefit of a lower rate under an income tax treaty, a Non-U.S. Holder must properly file with the applicable withholding agent an IRS Form W-8BEN, W-8BEN-E or other applicable form, claiming an exemption from or reduction in withholding under the applicable tax treaty. Such form must be provided prior to the payment of dividends and must be updated periodically. If a Non-U.S. Holder is eligible for a reduced rate of U.S. withholding tax pursuant to an income tax treaty, such holder may obtain a refund from the IRS of any excess amounts withheld by timely filing an appropriate claim for refund with the IRS.

If dividends are considered effectively connected with the conduct of a trade or business by a Non-U.S. Holder within the U.S. and, if required by an applicable income tax treaty, are attributable to a U.S. permanent establishment maintained by such Non-U.S. Holder, those dividends will be subject to U.S. federal income tax on a net basis at applicable graduated individual or corporate rates but will not be subject to withholding tax, provided a properly executed IRS Form W-8ECI, or other applicable form, is filed with the payor. Any effectively connected dividends paid to a foreign corporation may, under certain circumstances, be subject to an additional "branch profits tax" at a rate of 30% or a lower rate as may be specified by an applicable income tax treaty.

In the case of payments made outside the U.S. with respect to an offshore account, a Non-U.S. Holder may obtain the benefits of a reduced rate under an income tax treaty with respect to dividends paid with respect to the Common Stock by complying with certain alternative documentary evidence procedures directly or, under certain circumstances, through an intermediary. In addition, if a Non-U.S. Holder is required to provide an IRS Form W-8ECI or other applicable form, as discussed in the preceding paragraph, such holder must also provide its U.S. taxpayer identification number.

2.4 Gain on Disposition of the Common Stock

A Non-U.S. Holder will generally not be subject to U.S. federal income or withholding tax on any gain recognised on a sale or other disposition of the Common Stock unless:

- the gain is considered effectively connected with the conduct of a trade or business by such Non-U.S. Holder within the U.S. and, if required by an applicable income tax treaty, is attributable to a U.S. permanent establishment maintained by such Non-U.S. Holder;
- the Non-U.S. Holder is an individual who is present in the U.S. for 183 or more days in the taxable year of the sale or other disposition and certain other conditions are met; or
- the Company is or becomes a U.S. real property holding corporation (**"USRPHC"**).

The Company believes that it is not currently, was not in the past five years, and is not likely to become, a USRPHC. Even if the Company were to become a USRPHC, gain on the sale or other disposition of the Common Stock by a Non-U.S. Holder would generally not be subject to U.S. federal income tax, provided the Common Stock were "regularly traded on an established securities market" in the year of the disposition and such Non-U.S. Holder did not actually or constructively own more than 5% of the outstanding the Common Stock during the shorter of (i) the five-year period ending on the date of such disposition and (ii) the period of time during which such Non-U.S. Holder held such shares. Gain described in the first bullet point above will generally be subject to U.S. federal income tax on a net basis at applicable individual or corporate rates and, in the case of foreign corporations, the gain may, under certain circumstances, be subject to an additional branch profits tax equal to 30% or a lower rate as may be specified by an applicable income tax treaty.

2.5 Federal Estate Tax

Individuals, or an entity the property of which is includable in an individual's gross estate for U.S. federal estate tax purposes, should note that the Common Stock held at the time of such individual's death will be included in such individual's gross estate for U.S. federal estate tax purposes and may be subject to U.S. federal estate tax, unless an applicable estate tax treaty provides otherwise.

2.6 Information Reporting and Backup Withholding

The amount of dividends paid to a Non-U.S. Holder and the tax withheld with respect to those dividends must be reported annually to the IRS, regardless of whether withholding was required. Copies of the information returns reporting those dividends and withholding may also be made available to the tax authorities in the country in which a Non-U.S. Holder resides under the provisions of an applicable income tax treaty or other applicable agreements.

Backup withholding is generally imposed on certain payments to persons that fail to furnish the necessary identifying information to the payor. A Non-U.S. Holder will generally be subject to backup withholding with respect to dividends paid on the Common Stock unless such Non-U.S. Holder certifies its non-U.S. status to the payor. Dividends subject to withholding of U.S. federal income tax as described above under paragraph 2.3 of this Part VI (*Taxation*) would not be subject to backup withholding. The payment of proceeds of a sale of the Common Stock effected by or through a U.S. office of a broker or, in certain cases, by or through a U.S.-related foreign office of a broker, is subject to both backup withholding and information reporting unless a Non-U.S. Holder provides the payor with its name and address and certifies its non-U.S. status or otherwise establishes an exemption.

Backup withholding is not an additional tax. Any amounts withheld under the backup withholding rules will generally be allowed as a refund or a credit against a Non-U.S. Holders U.S. federal income tax liability, provided the required information is furnished in a timely manner to the IRS.

2.7 **Additional Withholding Requirements**

In addition to withholding taxes discussed above, under sections 1471 through 1474 of the IRS Code (commonly referred to as **"FATCA"**) a 30% U.S. federal withholding tax will generally be imposed on dividends paid by U.S. issuers, and on the gross proceeds from the disposition of certain stock, paid to or through a "foreign financial institution" (as specially defined under these rules), unless such institution (i) enters into an agreement with the U.S. Treasury to collect and provide to the U.S. Treasury substantial information regarding U.S. account holders, including certain account holders that are foreign entities with U.S. owners, with such institution or (ii) is deemed compliant with, or otherwise exempt from, FATCA. In certain circumstances, the information may be provided to local tax authorities pursuant to intergovernmental agreements between the U.S. and a foreign country. FATCA also generally imposes a U.S. federal withholding tax of 30% on the same types of payments to or through a non-financial foreign entity unless such entity (i) provides the withholding agent with a certification that it does not have any substantial U.S. owners (as defined under these rules) or a certification identifying the direct and indirect substantial U.S. owners of the entity or (ii) is deemed compliant with, or otherwise exempt from, FATCA. Satisfaction of the requirements under, or an exemption from, FATCA is typically evidenced by delivery of a properly completed IRS Form W-8BEN-E. FATCA would apply to dividends paid on the Common Stock and will apply to the gross proceeds from sales or other dispositions of the Common Stock on or after January 1, 2019. Under certain circumstances, a beneficial owner may be eligible for refunds or credits of such taxes. Non-U.S. Holders should consult their tax advisors regarding the possible implications of FATCA on their ownership of the Common Stock.

PART VII – ADDITIONAL INFORMATION

1. RESPONSIBILITY STATEMENT

1.1 The Company and the Directors, whose names appear on page 35 of this Prospectus, accept responsibility for the information contained in this Prospectus. To the best of the knowledge of the Company and the Directors (who have taken all reasonable care to ensure that such is the case), such information is in accordance with the facts and this Prospectus does not omit anything likely to affect the import of such information.

1.2 McDaniel & Associates Consultants Ltd. accepts responsibility for the information contained in the Competent Person's report as set out in Appendix 2 (*Competent Person's Report*). To the best of the knowledge of McDaniel & Associates Consultants Ltd. (who has taken all reasonable care to ensure that such is the case), the information contained in the Competent Person's Report is in accordance with the facts and does not omit anything likely to affect the import of such information.

2. INCORPORATION AND REGISTERED OFFICE

2.1 The Company was incorporated on 6 June 2003 under the name "Gran Tierra Energy Inc." as a corporation under the laws of the State of Nevada, United States. The Company was subsequently converted on 31 October 2016 into a corporation existing under the laws of the State of Delaware, United States. The Company currently operates under the General Corporation Law of the State of Delaware, as from time to time amended. The Company's registered number is 6198266.

2.2 Gran Tierra's principal place of business is at 900, 520 - 3 Avenue SW, Calgary, Alberta, Canada T2P 0R3. Its registered office is The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington Delaware 19801, New Castle County, Delaware, United States. Its telephone number is +1 403 265-3221.

2.3 The principal legislation under which the Company operates, and under which the Common Stock was authorised, is the General Corporation Law of the State of Delaware. The Company operates in conformity with its Bylaws.

3. SUBSIDIARY UNDERTAKINGS

The Company is the holding company of the Group and as at the Latest Practicable Date, the Company has the following direct and indirect subsidiaries:

Name[(1)]	**Jurisdiction of Incorporation**
Gran Tierra Callco ULC	Alberta, Canada
Petrolifera Petroleum (Colombia) Limited	Cayman Islands
Gran Tierra Energy Cayman Islands Inc.	Cayman Islands
Gran Tierra Energy Canada ULC	Alberta, Canada
Argosy Energy LLC	Delaware, U.S.
Gran Tierra Energy Mexico Holdings 1 LLC	Delaware, U.S.
Gran Tierra Energy Mexico Holdings 2 LLC	Delaware, U.S.
Gran Tierra Energy Colombia, Ltd.	Utah, U.S.
Gran Tierra Resources Limited	Alberta, Canada
Gran Tierra Energy International Holdings Ltd	Cayman Islands

Name[1]	Jurisdiction of Incorporation
Gran Tierra Luxembourg Holdings S.a.r.l. (*in liquidation*)	Luxembourg
Gran Tierra Colombia Inc.	Cayman Islands
Suroco Energy Venezuela	Venezuela
Vetra Petroamerica P&G Corp.[2]	Barbados
Southeast Investment Corporation[3]	Panama
Gran Tierra (PUT-7) Limited	Cayman Islands
Petrolatina Energy Limited (*in liquidation*)	United Kingdom
Petrolatina (CA) Limited (*in liquidation*)	United Kingdom
R.L. Petroleum Corp.	Panama
North Riding Inc.	Panama
Petroleos Del Norte S.A. (*in liquidation*)	Colombia
Taghmen Colombia S.L.	Spain
Taghmen Argentina Limited (*in liquidation*)	United Kingdom
Gran Tierra México Energy. S. de R. de C.V.	Mexico

Notes:

(1) All subsidiaries are wholly-owned subsidiaries unless otherwise indicated.

(2) 72.5% ownership by Gran Tierra Colombia Inc. The remaining 27.5% is owned by Vetra Southeast S.L. (not a member of the Group).

(3) *Direct Ownership*: Vetra Petroamerica P&G Corp. 67.67%; Vetra Southeast S.L. (not a member of the Group) 32.33%. *Indirect Ownership*: Gran Tierra 49.06% through interest in Vetra Petroamerica P&G Corp.; Vetra Southeast S.L. (not a member of the Group) 50.94% through a 32.33% direct ownership and an 18.61% indirect interest through Vetra Petroamerica P&G Corp.

4. SHARE CAPITAL

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

4.2 Details of changes in the share capital for the years ended 31 December 2015, 2016 and 2017, the six months ended 30 June 2018 and the period to the Latest Practicable Date are set out in the following table.

	Period from 30 June 2018 to the Latest Practicable Date	Six months ended 30 June 2018	Year ended 31 December		
			2017	2016	2015
Balance, beginning of period	390,017,518	385,191,042	390,807,194	273,442,799	276,072,351
Options exercised	198,932	319,462	-	2,165,370	390,000
Exchange of exchangeable shares(1)	1,135,239	4,976,426	2,088,229	372,172	1,547,595
Shares repurchased and cancelled	(35,200)(2)	(469,412)(2)	(7,704,381)(3)	-	(4,567,136)(4)
Shares cancelled	-	-	-	-	(11)
Shares issued upon conversion of subscription receipts(5)	-	-	-	57,835,134	-
Shares issued upon public offering(6)	-	-	-	43,335,000	-
Shares issued for acquisition	-	-	-	13,656,719	-
Balance, end of period	391,316,489	390,017,518	385,191,042	390,807,194	273,442,799

Notes:

(1) The Company previously had in issue one share of Special A Voting Stock, $0.001 par value, representing shares in Gran Tierra Goldstrike Inc., which were exchangeable on a 1-for-1 basis into the Common Stock (the **"Goldstrike Exchangeable Shares"**), and one share of Special B Voting Stock, $0.001 par value, representing shares in Gran Tierra Exchangeco Inc. which were exchangeable on a 1-for-1 basis into the Common Stock (the **"Exchangeco Exchangeable Shares"**). The Exchangeco Exchangeable Shares were issued upon the acquisition of Solana. The Goldstrike Exchangeable Shares were issued upon the business combination between Gran Tierra Energy Inc., an Alberta corporation, and Goldstrike, Inc., which is now the Company. On 1 May 2018, Gran Tierra Exchangeco Inc., a subsidiary of the Company, announced that it had established a redemption date of 5 July 2018 in respect of all of its outstanding exchangeable shares. Effective 5 July 2018, all remaining outstanding exchangeable shares of record on 4 July 2018 were acquired for purchase consideration of one share of Common Stock, and on 9 July 2018, the Company retired and cancelled one share of Special A Voting Stock and one share of Special B Voting Stock, which held voting rights in connection with those exchangeable shares. As a result, no shares of Special A Voting Stock and Special B Voting Stock remain outstanding.

(2) On 7 March 2018, the Company announced that it intended to implement a share repurchase program (the **"2018 Program"**) through the facilities of the TSX and eligible alternative trading platforms in Canada. The Company received regulatory approval from the TSX to commence the 2018 Program on 12 March 2018. The Company is able to purchase at prevailing market prices up to 19,269,732 shares of Common Stock, representing approximately 5% of the Company's issued and outstanding shares of Common Stock as of 8 March 2018. Shares purchased pursuant to the 2018 Program to date have been cancelled. The

2018 Program will expire on 11 March 2019, or earlier if the 5.00% share maximum is reached. The 2018 Program could be terminated by the Company at any time, subject to compliance with regulatory requirements. As such, there can be no assurance regarding the total number of shares that may be repurchased under the 2018 Program.

The table below summarises the shares of Common Stock purchased by the Company under the 2018 Program as at 31 August 2018, being the latest practicable date prior to the publication of this Prospectus.

	Total Number of Shares Purchased[a]	**Average Price Paid per Share [b]**	**Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs**	**Maximum Number of Shares that May Yet be Purchased Under the Plans or Programs**
March 1-31, 2018	464,912	2.57	464,912	18,804,820
April 1-30, 2018	—	—	—	18,804,820
May 1-31, 2018	4,500	2.98	4,500	18,800,320
June 1- 30, 2018	—	—	—	18,800,320
July 1-31, 2018	—	—	—	18,800,320
August 1-31, 2018	35,200	2.99	35,200	18,765,120
	504,612	2.60	504,612	18,765,120

Notes:

(a) Based on the settlement date.

(b) Exclusive of commissions paid to the broker to repurchase the Common Stock.

(3) During 2017, the Company repurchased and cancelled 7.7 million shares at an average price of $2.33 for total cost of $17.9 million, pursuant to the terms of a share repurchase programme through the facilities of the TSX, the NYSE American and eligible alternative trading platforms in Canada and the United States. The programme expired on 7 February 2018.

(4) During 2015, the Company repurchased and cancelled 4.6 million shares at an average price of $2.19 for total cost of $10.0 million, pursuant to the terms of a share repurchase program through the facilities of the TSX, the NYSE MKT (the predecessor to the NYSE American) and eligible alternative trading platforms in Canada and the United States. The programme expired on 29 July 2016.

(5) On 8 July 2016, the Company issued approximately 57.8 million subscription receipts (**"Subscription Receipts"**) in a private placement to eligible purchasers at a price of $3.00 per Subscription Receipt for gross proceeds of $173.5 million, or net proceeds after share issuance costs of $165.8 million. The proceeds were used to partially fund the PetroLatina acquisition. Each Subscription Receipt entitled the holder to automatically receive one share of Common Stock upon closing of the PetroLatina acquisition on the satisfaction of certain conditions. Upon the closing of the PetroLatina acquisition on 23 August 2016, each Subscription Receipt was converted to one share of Common Stock.

(6) On 29 November 2016, the Company issued approximately 43.3 million shares of Common Stock at a public offering price of $3.00 per share for gross proceeds of $130.0 million, or net proceeds after share issuance costs of $123.0 million (the **"Offering"**). The proceeds were used to repay borrowings outstanding under the Company's revolving credit facility.

4.3 As at the Latest Practicable Date:

(a) the outstanding share capital consists of 391,316,489 shares of Common Stock (all of which were fully paid); and

(b) the Company held no treasury shares.

4.4 The Common Stock have been created under the Delaware General Corporation Law and they conform with laws of the State of Delaware. The Common Stock have been and will be duly authorised according to the requirements of the Certificate of Incorporation and Bylaws and have and will have all necessary statutory and other consents. The shares of Common Stock are in registered, book-entry form.

4.5 The holders of shares of Common Stock are entitled to one vote for each share on all matters submitted to a stockholder vote and are entitled to share in all dividends that the Board, in its discretion, declares from legally available funds. The holders of Common Stock have no pre-emptive rights, no conversion rights, and there are no redemption provisions applicable to the shares.

4.6 Further information on the rights attaching to the Common Stock is set out in paragraph 5.3 of this Part VII (*Additional Information*).

4.7 As at the date of this Prospectus, and save as otherwise disclosed in this Part VII (*Additional Information*):

(a) no share or loan capital of the Company has, since the incorporation of the Company, been issued or agreed to be issued, or is now proposed to be issued, fully or partly paid, either for cash or for a consideration other than cash, to any person;

(b) no commission, discounts, brokerages or other special terms have been granted by the Company in connection with the issue or sale of any share or loan capital; and

(c) no share or loan capital of the Company is under option or agreed, conditionally or unconditionally, to be put under option.

5. CERTIFICATE OF INCORPORATION AND BYLAWS

The Certificate of Incorporation, which was adopted on 31 October 2016 and amended on 9 July 2018, and the Bylaws, which were adopted on 31 October 2016, are available for inspection at the address specified in paragraph 19.1 of this Part VII (*Additional Information*). The Certificate of Incorporation and Bylaws contain provisions (among others) to the following effect:

5.1 Purpose

Pursuant to the Company's Certificate of Incorporation, the purpose of Gran Tierra is to engage in any lawful act or activity for which corporations may be organised under the General Corporation Law of the State of Delaware (as amended from time to time) (the **"DGCL"**).

5.2 Authorised Share Capital

The Company is authorised to issue up to 595,000,000 shares of stock consisting of (a) 570,000,000 shares of Common Stock; and (b) 25,000,000 shares of Preferred Stock. As at the Latest Practicable Date, the outstanding share capital consists of 391,316,489 shares of Common Stock.

5.3 Rights attaching to the Common Stock

(a) *Voting rights*

Each outstanding share of Common Stock shall entitle the holder thereof to one vote on each matter properly submitted to stockholders for their vote. Cumulative voting is not permitted for the election of individuals to the Board or for any other matters brought before any meeting of stockholders, regardless of the nature thereof.

Each stockholder may vote in person or by proxy, but no proxy shall be voted after three years from the date of its creation, unless such proxy provides for a longer period. A stockholder may revoke any proxy which is not irrevocable by attending the meeting and voting in person, or by filing with the person recording the proceedings of the meeting an instrument in writing revoking the proxy or another duly executed proxy bearing a later date.

(b) *Dividends, Redemption, Preferences*

The Board may from time to time declare, and the Company may pay, dividends on its outstanding shares of Common Stock in the manner and on the terms and conditions provided by law.

All Common Stock have the same rights and preferences. All Common Stock when issued shall be fully paid and non-assessable. Shareholders shall not be entitled to any pre-emptive or preferential rights to acquire additional Common Stock.

5.4 Transfer of shares

Neither the Certificate of Incorporation nor the Bylaws contain any restrictions on the free transferability of the shares of Common Stock. The shares of Common Stock are transferable upon the Company's books by holders thereof in person or by their duly authorised attorney or legal representatives and upon such transfer, the old certificates (in the case of certificated shares) shall be surrendered to the Company.

5.5 Amendment of the Certificate of Incorporation and Bylaws

The Company has reserved the right to amend, alter, change or repeal any provision in the Certificate of Incorporation in any manner prescribed by the laws of the State of Delaware. The Bylaws are subject to alteration or repeal and new Bylaws may be made by the stockholders holding no less than a majority of the votes represented by the then-issued and outstanding shares of Common Stock entitled to vote thereon at an annual meeting or a special meeting called for that purpose. The Board has the power to make, adopt, alter, amend and repeal, from time to time, the Bylaws. However, the affirmative vote of the stockholders holding a majority of the voting power of all of the then-issued and outstanding shares of Voting Stock shall be required to amend the provision in the Bylaws relating to the maximum and minimum number of directors.

5.6 Shareholder Meetings

(a) *Annual Meetings and Special Meetings*

Annual meetings of stockholders may be held at such place, either within or outside of the State of Delaware, and at such time and date as the Board may by resolution determine and as set forth in the notice of meeting. The Board may, in its sole discretion, determine that a meeting of stockholders will be held solely by means of remote communication as authorised by section 211(a)(2) of the DGCL, as amended from time to time. At each annual meeting, the stockholders entitled to vote shall elect a board of directors and may transact such other corporate business as stated in the notice of meeting.

A special meeting of stockholders may be called by the chairman of the Board, by a vote of a majority of the directors then in office or by the secretary upon the written request of holders of record of at least 25% of the outstanding common stock of the Company at the time such request is properly submitted by the relevant stockholders.

(b) *Notice of Meeting*

Written or printed notice of a shareholder meeting shall be delivered by the Company not less than 10 days nor more than 60 days before the date of the meeting, either personally or by mail, to each stockholder of record entitled to vote at such meeting.

Only such business shall be conducted at a special meeting of stockholders as shall have been brought before the meeting pursuant to the Company's notice of meeting and as shall have been accompanied by a notice setting forth the information required by the Bylaws.

(c) *Quorum*

Holders of shares representing a majority of the total number of votes which may be cast by all holders of Voting Stock, represented in person or by proxy, shall constitute a quorum at a meeting of stockholders.

(d) *Action without a meeting*

Unless otherwise provided by law and subject to procedures set forth in the Bylaws, any action required to be, or which may be, taken at a meeting of stockholders may be taken without a meeting, without prior notice and without a vote if written consents are signed by stockholders holding Voting Stock representing a majority of votes entitled to be cast at such a meeting, or such other proportion as is required by law, the Certificate of Incorporation or the Bylaws.

Every written consent shall bear the date of signature of each stockholder who signs the consent and no written consent shall be effective unless, within 60 days of the earliest dated consent delivered to the Company, written consents signed by a sufficient number of holders to take action are delivered to the Company in a manner permitted by applicable law. No action by written consent without a meeting shall be effective until such date as the secretary or other authorised officer or inspector completes their review, determines that the consents delivered to the Company are not less than the minimum number of votes required and certifies such determination to the Board for entry in the records of the Company. A stockholder may revoke the consent in any manner permitted by applicable law.

Prompt notice of the taking of corporate action without a meeting by less than unanimous written consent shall be given to those stockholders who have not consented in writing and who, if the action had been taken at a meeting, would have been entitled to notice of the meeting if the record date for such meeting had been the date that written consents signed by a sufficient number of holders to take action were delivered to the Company.

5.7 **Directors**

The business and affairs of the Company shall be managed by or under the direction of the Board. In addition to the powers and authorities conferred on the Board by the Bylaws, the Board may exercise all such powers of the Company and do all such lawful acts and things as are not by the DGCL, the Certificate of Incorporation or the Bylaws required to be exercised or done by the stockholders.

(a) *Number and Qualifications*

The Board may and the number of directors may from time to time be increased or decreased by a resolution of the Board, provided the number shall not be reduced to fewer than one. The Board shall consist of not less than one and not more than nine directors.

To be eligible to be a nominee for election as a director, each proposed nominee must deliver to the Company:

(i) a written questionnaire with respect to the background and qualification of such proposed nominee;

(ii) a written representation and agreement that such proposed nominee:

(A) is not and will not become a party to (1) any agreement, arrangement or understanding with, and has not given any commitment or assurance to, any person or entity as to how such proposed nominee, if elected to as a director, will act or vote on any issue or question that has not been disclosed to the Company; or (2) any voting commitment that could limit or interfere with his/her ability to comply with his/her fiduciary duties under applicable law;

(B) is not and will not become party to any agreement, arrangement or understanding with any person or entity other than the Company with respect to any direct or indirect compensation, reimbursement or indemnification in connection with service or action as a director that has not been disclosed to the Company; and

(C) in such proposed nominee's individual capacity and on behalf of the stockholder (or, if different, beneficial owner) on whose behalf nomination is made, would be in compliance and will comply with applicable, publicly disclosed corporate governance, conflict of interest, confidentiality and stock ownership and trading policies and guidelines of the Company.

The Company may request additional information to determine the eligibility of a proposed nominee or information that could be material to a reasonable stockholder's understanding of independence or lack of independence.

(b) *Tenure*

Directors shall be elected by a majority of the votes cast by the holders of Voting Shares at a meeting of stockholders at which a quorum is present. However, if the number of nominees exceeds the number of directors to be elected, directors shall be elected by a plurality of the votes cast. Unless the director election standard is a plurality, if a director is not elected by a majority of votes cast, the director shall promptly tender his or her resignation to the Board for consideration. The Nominating and Corporate Governance Committee shall make a recommendation to the Board on whether to accept or reject the director's resignation or whether other action should be taken. The Nominating and Corporate Governance Committee shall recommend, and the Board's decision shall be, to accept the resignation absent exceptional circumstances. If the Board decides not to accept a resignation, it shall publicly disclose its decision including the reasons for such decision.

Directors shall hold office until the next meeting of stockholders for the purposes of electing the Board or until their successors have been duly elected and qualified or until a director's prior death, resignation or removal. Any director may resign at any time upon written notice to the Company. Between successive annual meetings, the directors shall have the power to appoint one or more additional directors to fill any vacancies occurring for any reason other than removal. A director so appointed shall hold office only until the next following annual meeting of the Company or until his successor is duly elected and qualified, but such director shall be eligible for election at the next meeting of stockholders for the purpose of electing directors.

Any director may be removed, with or without cause, from office at any time by the affirmative vote of the holders of at least two-thirds of the voting power of all of the then-outstanding shares of capital stock of the Company entitled to vote generally in the election of directors, voting together as a single class of stock.

(c) *Quorum*

A whole number of directors equal to at least a majority of directors then in office shall constitute a quorum for the transaction of business. The act of the majority of directors present at a meeting at which a quorum is present shall be the act of the Board.

(d) *Committees*

The Board may, by resolution adopted by a majority of directors then in office, designate one or more committees to exercise, subject to applicable law, the powers of the Board in the management of the business and affairs of the Company when the Board is not in session. Each such committee shall consist of two or more directors.

(e) *Compensation*

Pursuant to the Bylaws, directors shall not receive any stated salary for their services as directors or members of committees, but a fixed fee and expenses of attendance may be allowed for attendance at each meeting.

5.8 **Forum for Adjudication of Disputes**

Pursuant to the Bylaws, to the fullest extent permitted by law and unless the Company consents in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware shall be the sole and exclusive forum for: (a) any derivative action or proceeding brought in the name or right of the Company or on its behalf; (b) any action asserting a claim for breach of a fiduciary duty owed by any director, officer, employee, stockholder or other agent of the Company to the Company or its stockholders; (c) any action arising or asserting a claim arising pursuant to any provision of the DGCL, the Certificate of Incorporation or the Bylaws or as to which the DGCL confers jurisdiction on the Court of Chancery of the State of Delaware; or (d) any action asserting a claim governed by the internal affairs doctrine, including, without limitation, any action to interpret, apply, enforce or determine the validity of the Certificate of Incorporation or the Bylaws. Any person or entity purchasing or otherwise acquiring any interest in shares of Common Stock shall be deemed to have notice of and consented to the provisions of this article.

6. DIRECTORS AND SENIOR MANAGEMENT

6.1 Other directorships and partnerships

Details of those companies and partnerships outside the Group of which the Directors and Senior Management are currently directors or partners, or have been directors or partners at any time during the five years prior to the date of this Prospectus, are set out in the table below.

Director/Member of Senior Management	Current Directorships/Partnerships	Past Directorships/Partnerships
Directors		
Robert B. Hodgins	AltaGas Ltd	Caracal Energy Inc.
	EnerPlus Corporation	Santonia Energy Inc.
	MEG Energy Corp.	Skope Energy Inc.
	Canbriam Energy Inc.	Cub Energy Inc.
		Fairborne Energy Trust
		Kicking Horse Energy
		MGM Energy Corp.
		Jaguar Resources Inc. (formerly Lateral Capital Corp.)
		Contact Exploration Inc.
		StonePoint Energy Inc.
		Bukit Energy Inc.
		Kicking Horse Oil & Gas Ltd.
Peter J. Dey	Paradigm Capital Inc.	Caracal Energy Inc.
		Goldcorp Inc.
		Granite Real Estate Inc. (formerly MI Developments Inc.)
		Granite Real Estate Investment Trust
		Enablence Technologies Inc.

Director/Member of Senior Management	Current Directorships/Partnerships	Past Directorships/Partnerships
		Addax Petroleum Corp. Massachusetts Museum of Contemporary Art
Gary S. Guidry	Africa Oil Corp. PetroTal Corp.	ShaMaran Petroleum Corp. Caracal Energy Inc. TransGlobe Energy Corporation Bukit Energy Inc.
Evan Hazell	Kaisen Energy Black Swan Energy Primavera Resources Paul Hardy Fashion Inc.	Oryx Petroleum Corporation Limited
Ronald W. Royal	Valeura Energy Inc.	Caracal Energy Inc. Oando Energy Resources Inc. (formerly Exile Resources Inc.)
Sondra Scott	Verisk Maplecroft Verisk Analytics	Wood Mackenzie
David P. Smith	Superior Plus Corp. 2052759 Ontario Inc. The Bluff's Hunting Club	Xinergy Ltd.
Brooke Wade	Kinder Morgan Canada Limited Wade Capital Corporation Wade Capital (US) Corporation Wade Capital (Maui) Corporation 6551238 Canada Inc. Belkin Enterprises Ltd. Novinium Inc. Thistle Topco (UK) Ltd.	Caracal Energy Inc.
Senior Management		
Ryan Ellson	PetroTal Corp.	None
Ed Caldwell	Environmental & Regulatory Consulting (ERC) Inc.	None
James Evans	None	None
Alan Johnson	None	None
Glen Mah	GW Mah Petroleum Consultants Ltd.	None

Director/Member of Senior Management	Current Directorships/Partnerships	Past Directorships/Partnerships
Susan Mawdsley	None	None
Rodger Trimble	None	None
Lawrence West	None	None

As at the date of this Prospectus, none of the Directors:

(a) has any convictions in relation to fraudulent offences for at least the previous five years;

(b) was a director of a company, a member of an administrative, management or supervisory body or a senior manager of a company within the previous five years which has entered into any bankruptcy, receivership or liquidation proceedings; and

(c) has been subject to any official public incrimination and/or sanctions by statutory or regulatory authorities (including designated professional bodies) or has been disqualified by a court from acting as a member of the administrative, management or supervisory bodies of an issuer or from acting in the management or conduct of the affairs of any issuer for at least the previous five years.

6.2 **Director and Senior Management and other interests in the Company's share capital**

(a) *Director Share Ownership Requirements*

Gran Tierra has introduced a policy requiring directors to acquire common shares and/or DSUs equivalent in value to three times their annual cash retainer within five years from the date of first election to the Board. The following table sets out the non-executive director share ownership requirements for 2017:

	Ownership Requirement 2017
	3x annual Board cash retainer fees in Common Shares and DSUs
Chairman of the Board	$73,735 x 3 = $221,204
	3x annual Board cash retainer fees in Common Shares and DSUs
Non-Executive Directors	$43,842 x 3 = $131,527

As at 31 December 2017, all of the current Directors have met or have additional time to achieve their share ownership requirements.

(b) *Share Ownership Guidelines*

Gran Tierra has implemented share ownership guidelines for all of its executive officers, which are designed to align their long-term financial interests with those of the Shareholders. The NEO share ownership guidelines are as follows:

Position	Guideline	Ownership Relative to Base Salary as of 31 December 2017
Chief Executive Officer	3 X base salary	Exceeds
Chief Financial Officer	2 X base salary	Exceeds
Other NEOs	1 X base salary	Exceeds or In-Progress

If at any time an executive officer does not meet their ownership requirement, they must retain (a) any of the Common Stock owned by them (whether owned directly or indirectly) and (b) any net shares received as the result of the exercise, vesting or payment of any equity award until the ownership requirement is met, in each case unless otherwise approved by the Compensation Committee. For this purpose, "net shares" means the shares of stock that remain after shares are sold or withheld to (i) pay the exercise price for a stock option award or (ii) satisfy any tax obligations, including withholding taxes, arising in connection with the exercise, vesting or payment of an equity award.

Compliance with these requirements is evaluated as of 31 December of each year. The value of an individual's share ownership as of such date is determined by multiplying the number of shares of the Common Stock or other eligible equity interests held by the individual by the greater of the purchase price of the stock or the closing price on 31 December of each year.

In determining stock ownership levels, shares of common stock held directly or indirectly by the officer (including shares beneficially owned in a trust, by a limited liability company or partnership, and by a spouse and/or minor children) are included. Outstanding RSUs, PSUs and unexercised stock options are not included. If an executive officer does not satisfy the stock ownership requirements, they must retain all shares acquired on the vesting of equity awards or the exercise of stock options (net of exercise costs and taxes) until compliance is achieved.

(c) As at the Latest Practicable Date, the interests of the Directors and Senior Management in the Company's share capital are set out in the table below. This table does not take account of any outstanding awards or options over the Common Stock granted to the Directors or Senior Management, which are detailed below in paragraph 6.2(d) of this Part VII (*Additional Information*).

Director/Member of Senior Management	**Number of shares**	**Percentage of total issued share capital**
Director		
Robert B. Hodgins	10,000	0.0%
Gary S. Guidry	2,527,000	0.6%
Peter J. Dey	20,000	0.0%
Evan Hazell	55,000	0.0%
Ronald W. Royal	254,667	0.1%
Sondra Scott	0	-
David P. Smith(1)	265,000	0.1%
Brooke Wade(2)	642,600	0.0%
Senior Management		
Ryan Ellson(3)	266,030	0.1%
Ed Caldwell	15,000	0.0%
James Evans(4)	251,405	0.1%
Alan Johnson(5)	59,080	0.0%
Glen Mah	50,000	0.0%
Susan Mawdsley	56,000	0.0%

Director/Member of Senior Management	Number of shares	Percentage of total issued share capital
Rodger Trimble	67,850	0.0%
Lawrence West	245,030	0.1%
Total	4,784,662	1.2%

Notes:

(1) Includes 122,500 owned by spouse.

(2) 242,600 held directly; 400,000 held indirectly.

(3) Includes 30,000 owned by spouse.

(4) Includes 61,000 owned by spouse.

(5) Includes 7,880 owned by spouse.

(d) As at the Latest Practicable Date, the Directors and Senior Management had the following outstanding awards or options over the Common Stock.

Director/Member of Senior Management	Number of DSUs	Number of RSUs	Number of PSUs	Stock Options
Director				
Robert B. Hodgins	97,227	0	0	98,778
Gary S. Guidry	0	0	991,712	1,167,803
Peter J. Dey	101,427	0	0	115,655
Evan Hazell	89,015	0	0	115,655
Ronald W. Royal	133,876	0	0	115,655
Sondra Scott	40,791	0	0	85,000
David P. Smith	42,163	0	0	115,655
Brooke Wade	133,876	0	0	115,655
Senior Management				
Ryan Ellson	0	0	718,299	761,262
Ed Caldwell	0	0	414,370	334,727
James Evans	0	0	424,920	443,259
Alan Johnson	0	0	424,920	443,259
Glen Mah	0	0	424,904	240,504
Susan Mawdsley	0	0	416,442	301,682
Rodger Trimble	0	0	408,258	237,049
Lawrence West	0	0	424,920	443,259

(e) As at the Latest Practicable Date, or, where indicated, the date set forth in the footnotes to the table below, in so far as is known to the Company and except as disclosed below, no person is, directly or indirectly, interested in five per cent. or more of the outstanding shares of Common Stock.

Shareholder	Number of shares	Percentage of total issued share capital
GMT Capital Corp.[(1)]	63,925,906	16.3%
Luminus Management, LLC[(2)]	20,788,164	5.3%

Notes:

(1) Based on information on SEDI filed on 11 September 2018.

(2) Based on a Form 13F filed on EDGAR on 14 August 2018.

There are no different voting rights for any holder of shares of Common Stock.

(f) Save as disclosed in paragraph 6.2 of this Part VII (*Additional Information*), no Director or member of Senior Management has any interests (beneficial or non-beneficial) in the Company's share capital or any other securities of the Company.

(g) Save as disclosed in paragraph 6.2(e) of this Part VII (*Additional Information*), the Company is not aware of any person who directly or indirectly, jointly or severally, exercises or, immediately after Admission, could exercise control over the Company.

6.3 **Director' terms of appointment**

(a) *Non-executive directors*

As is common practice in the U.S. and in Canada, the non-executive directors are elected by the Shareholders on an annual basis and do not have service agreements or appointment letters.

The Directors are appointed at each annual meeting of the Shareholders and may also be appointed at a special meeting of Shareholders. Directors hold office until the close of the next annual meeting or until a successor is duly elected or appointed or his or her office is earlier vacated in accordance with the DGCL. The duties and responsibilities of the Board and significant issues of corporate governance are set out in the Company's Corporate Governance Guidelines which are regularly reviewed by the Nominating and Corporate Governance Committee.

The director compensation structure for non-executive directors consists of an all-inclusive Board retainer and consists of both a cash component and an equity component. Please see below at paragraph 6.4(a) of this Part VII (*Additional Information*) for further information in relation to the Directors' compensation structure. Non-executive director compensation is reviewed annually by the Nominating and Corporate Governance Committee to ensure that it is reasonable in light of the time required from directors and aligns directors' interests with those of the Company's stockholders.

None of the non-executive directors are entitled to any benefits upon termination of their employment.

(b) *Executive director*

The employment of the President and the Chief Executive Officer, Gary Guidry, are governed by the terms of an executive employment agreement. The Compensation Committee approves the terms of all NEO employment agreements, including that of Mr. Guidry. The terms of those agreements were structured to attract and retain persons key to Gran Tierra's success, as well as to be competitive with compensation practices for executives in similar positions at companies of similar size and complexity. In assessing whether the terms of the employment agreements were competitive, the Compensation Committees received advice from Gran Tierra's Compensation Consultant and reviewed appropriate surveys and industry benchmarking data. Mr. Guidry's employment agreement does not have a fixed term. The terms of his employment agreement provides for certain payments and benefits in connection with a termination of employment and corporate transaction.

In the event that Mr. Guidry die, voluntarily resign (without good reason, as defined below), or his employment is terminated by Gran Tierra for cause (as defined below), he will not be entitled to receive any further compensation or benefits whatsoever other than those which have accrued up to his last day of active service. Pursuant to Mr. Guidry's employment agreement, "cause" means any act or omission of the executive which would, at common law, permit an employer to terminate the employment of an employee without notice or payment in lieu of notice. "Good reason" generally means any of the following without Mr. Guidry's express written consent:

(i) an adverse change in position, titles, duties or responsibilities, except in connection with the termination of employment for cause;

(ii) a reduction by the company of Mr. Guidry's base salary except to the extent that the annual base salaries of all other executive officers are similarly reduced or any change in the basis upon which his annual compensation is determined or paid if the change is adverse to him (excluding changes to the annual bonus);

(iii) a change in control of Gran Tierra Energy Inc. or Gran Tierra Energy Canada ULC occurs; or

(iv) any breach by the Company of any material provision of the employment agreement.

In the event of an involuntary termination of employment by Gran Tierra other than for cause or a termination of employment by Mr. Guidry for good reason Mr. Guidry is entitled to a severance payment equal to two times the sum of his base salary and bonus earned during the 12 months preceding the termination of his employment. Upon a termination of employment, Mr. Guidry forfeits any unvested RSUs and stock options.

In addition, if Mr. Guidry is required to file a U.S. income tax return with the Internal Revenue Service, and if any of the payments or benefits received or to be received by him constitute "parachute payments" within the meaning of Section 280G of the IRS Code and will be subject to the excise tax imposed under Section 4999 of the IRS Code (the **"Excise Tax"**), the Company shall pay to Mr. Guidry, no later than the time such Excise Tax is required to be paid by him or withheld by the Company, an additional amount equal to the sum of the Excise Tax payable by Mr. Guidry, plus the amount necessary to put him in the same after-tax position as if no Excise Tax had been imposed. The Company believes that to ensure Gran Tierra's executive compensation remains competitive, the Chief Executive Officer should be tax equalised to his Canadian citizen colleagues on payments that are subject to U.S. Excise Tax. In 2017, this amount would have been $1,669,682.

The table below estimates the amounts payable if an involuntary termination of employment without cause, a termination for good reason or a specified corporate transaction had occurred on 31 December 2017, for Mr. Guidry using $2.70, the closing price of the stock on that date.

	Acceleration of Vesting				
Name	**Cash Severance ($)**	**Stock Options ($)(1)**	**RSUs ($)**	**PSUs ($)(1)**	**Total ($)**
Gary S. Guidry (2)					
Termination without Cause or Resignation for Good Reason	1,445,994	—	—	—	1,445,994
Corporate Transaction	—	29,026	85,501	1,723,680	1,838,207
Termination without Cause or Resignation for Good Reason following a Corporate Transaction	1,445,994	29,026	85,501	1,723,680	3,284,201

Notes:

(1) Unvested equity awards will accelerate and become fully vested immediately prior to a Corporate Transaction. With respect to stock options, the value is calculated as (a) the difference between $2.70, the closing price of the Common Stock on 29 December 2017, and the exercise price of the applicable option, multiplied by (b) the number of unvested options subject to accelerated vesting held by Mr. Guidry. With respect to RSUs, the value is calculated as (a) $2.70, the closing price of the Common Stock on 29 December 2017, multiplied by (b) the number of unvested RSUs subject to accelerated vesting held Mr. Guidry. With respect to PSUs, the value is calculated as (a) $2.70, the closing price of the Common Stock on 29 December 2017, multiplied by (b) the number of unvested PSUs subject to accelerated vesting held by Mr. Guidry, assuming a performance factor of 1.

(2) Under the terms of Mr. Guidry's employment agreement, as he is required to file a U.S. income tax return with the Internal Revenue Service, and as certain payments or benefits received or to be received by him constitute "parachute payments" within the meaning of Section 280G of the IRS Code and will be subject to the Excise Tax, the Company shall pay to Mr. Guidry, no later than the time such Excise Tax is required to be paid by Mr. Guidry or withheld by the Company, an additional amount equal to the sum of the Excise Tax payable by Mr. Guidry, plus the amount necessary to put him in the same after-tax position as if no Excise Tax had been imposed. In 2017, this amount would have been $1,669,682.

(c) The Company maintains an insurance policy for directors' and officers' liability. It provides coverage for costs incurred to defend and settle claims against directors or officers up to an annual limit of $100 million. The cost of coverage for 2017 was approximately $390,000. Directors and officers do not pay any portion of the premiums. No claims were made or became payable in 2017.

6.4 Compensation Structure

(a) *Directors*

The objective of Gran Tierra's compensation programme for non-executive directors is to attract and retain directors of a quality and nature that will enhance its long-term sustainable profitability and growth. Director compensation is intended to provide an appropriate level of remuneration considering the experience, responsibilities, time commitment and accountability of their roles. Any director who is also an employee of the Company does not receive additional compensation for serving as a director.

Non-executive director compensation is reviewed annually by the Nominating and Corporate Governance Committee to ensure that it is reasonable in light of the time required from directors and aligns directors' interests with those of Gran Tierra's stockholders.

In addition, Gran Tierra aligns the interests of its directors with its stockholders by requiring that Directors own a minimum number of shares or Deferred Stock Units (**"DSUs"**). Each non-executive director must hold shares or DSUs with a value equal to three times the annual cash retainer. The shareholdings of each non-executive director are valued using either the closing price of Gran Tierra's shares on 31 December each year or the value at the time they were acquired, whichever is greater. Directors have five years to meet the share ownership requirement. See paragraph 6.2(a) of this Part VII (*Additional Information*) for further information.

The director compensation structure for non-executive directors consists of an all-inclusive Board retainer and consists of both a cash component and an equity component. Each of these components is described below in more detail.

2017 Annual Cash Retainer and Travel Fees (1)		**2017 Annual Equity Retainer (DSUs, RSUs, Stock Options)**(1)
Chairman of the Board	$73,735	$103,627
Director	$43,842	$56,198
Audit Committee Chair	$35,871	
Other Committee Chairs	$23,914	
Committee Members	$11,957	
Travel Fee (over three hours) per meeting	$1,196	

Note:

(1) All compensation to non-employee directors is paid in Canadian dollars and converted into U.S. dollars for the purposes of the above table.

The cash retainer portion of the director's fees can be taken in the form of cash, restricted stock units (**"RSUs"**), DSUs or any combination thereof, as elected by each non-employee director. The equity portion must be taken in the form of equity until the stock ownership guideline is achieved. A maximum of 25% of the equity retainer can be taken as stock options which vest immediately and expire after five years. DSUs vest immediately but are not paid out until the director ceases to be a director of Gran Tierra. The number of DSUs, RSUs or stock options credited to each director is calculated by dividing the dollar value of the portion of the director's retainer to be paid in the form of DSUs, RSUs or stock options by the fair market value on the day of determination. A travel fee is paid to each director for travel over three hours to a Board meeting.

The following table shows for the fiscal year ended 31 December 2017, the value of amounts paid or granted to all non-employee directors of Gran Tierra:

Director	**Fees Earned or Paid in Cash ($)**(1)	**Option Awards ($)**	**All Other Compensation ($)**(4)	**Total ($)**
Peter J. Dey	130,752		5,381	136,133
Evan Hazell	131,999		1,196	133,195
Robert B. Hodgins	209,297		5,978	215,275
Ronald W. Royal	142,254		4,783	147,037
Sondra Scott	38,465	81,919	2,391	122,775
David P. Smith	145,735		5,978	151,713
Brooke Wade	142,254		1,196	143,450

Note:

(1) Amounts reported in this column represent Board and committee retainers. Cash fees that were deferred by an election of a director and received in the form of DSUs (Stock Awards) or Option Awards are reported in the table below. All compensation to non-employee directors is paid in Canadian dollars and converted into U.S. dollars for the purposes of the above table. For 2017 compensation amounts, the exchange rate at 29 December 2017 of one U.S. dollar to Canadian $1.2545 is used.

Director	Cash ($)	Stock Awards($)(2)	Option Awards ($)(3)
Peter J. Dey	—	117,233	13,519
Evan Hazell	32,881	85,599	13,519
Robert B. Hodgins	109,606	99,691	—
Ronald W. Royal	—	128,735	13,519
Sondra Scott	22,528	15,937	—
David P. Smith	91,670	40,546	13,519
Brooke Wade	—	128,735	13,519

Notes:

(2) Amounts in the Stock Awards column reflect the aggregate grant date fair value of DSUs computed in accordance with U.S. GAAP. The Company currently intends to settle the DSUs outstanding as of 31 December 2017 in cash, and, therefore, DSUs are accounted for as liability instruments. The amounts in this column include DSUs which were issued as a result of an election by the directors to be paid a portion of their retainer in the form of DSUs. The value ultimately realised by each director may or may not be equal to this determined value. As of 31 December 2017, each of the non-employee directors had aggregate outstanding DSUs as follows, all of which were fully vested: Mr. Dey – 71,120; Mr. Hazell – 66,887; Mr. Hodgins – 77,899; Mr. Royal – 100,595; Ms. Scott – 6,990; Mr. Smith – 31,682; and Mr. Wade – 100,595. None of the directors hold RSUs.

(3) Amounts in the Options Awards column reflect the aggregate grant date fair value computed in accordance with ASC 718. Assumptions made in the valuation of stock options granted are discussed in Note 7 (*Share Capital*) to the Group's consolidated financial statements for the financial year ended 31 December 2017 in Appendix 1 (*Historical Financial Information)*. The amounts in this column include stock options which were issued as a result of an election by the directors to be paid a portion of the equity retainer in the form of stock options. As of 31 December 2017, each of the non-employee directors had aggregate outstanding stock options as follows: Mr. Dey – 108,184; Mr. Hazell – 108,184; Mr. Hodgins - 85,000; Mr. Royal – 108,184; Ms. Scott – 85,000; Mr. Smith – 108,184 and Mr. Wade – 108,184.

(4) Amounts reported in this column represent fees paid for travel to or from a meeting of the Board in excess of three hours per meeting.

(b) *Senior Management*

The aggregate amount of remuneration paid (including any contingent or deferred compensation) and benefits in kind granted to senior managers of the Company for services in all capacities to the Group in the financial year ended 31 December 2017 was approximately $11.6 million.

6.5 Transactions with Directors and Senior Management

(a) None of the Directors or Senior Management has or has had any interest in any transaction which is or was unusual in its nature or conditions or significant to the business which was effected by the Company during the current or immediately preceding financial year, or which was effected during an earlier financial year and remains in any respect outstanding or unperformed.

(b) None of the Directors or Senior Management has or has had a beneficial interest in any contract to which the Company was a party during the current or immediately preceding financial year.

(c) No loan has been granted to, nor any guarantee provided for the benefit of, any Director or Senior Management by the Company.

(d) None of the Directors or Senior Management is considered to be subject to any conflicts of interest between his duties to the Company and his private interests or other duties.

7. 2007 EQUITY INCENTIVE PLAN

The only equity compensation plan approved by Gran Tierra's stockholders is the 2007 Equity Incentive Plan (the **"Plan"**), which is an amendment and restatement of Gran Tierra's 2005 Equity Plan (the **"Prior Plan"**). In accordance with the Plan, the Board is authorised to issue options or other rights to acquire shares of Common Stock. On 27 June 2012, the Shareholders approved an amendment to the Plan, which increased the Common Stock available for issuance thereunder from 23,306,100 shares to 39,806,100 shares.

The Plan, provides for the grant of stock options, restricted stock awards, stock appreciation rights, RSUs and other stock awards, collectively referred to as "Awards" for the purposes of this paragraph 7. To date, Gran Tierra has granted stock options, RSUs including DSUs and PSUs under the Plan.

7.1 Summary Terms of the 2007 Equity Incentive Plan

(a) *Purpose*

The Board adopted the Plan to provide a means by which employees, directors and consultants of Gran Tierra and its affiliates may be given an opportunity to acquire stock in Gran Tierra, to assist in retaining the services of such persons, to secure and retain the services of persons capable of filling such positions and to provide incentives for such persons to exert maximum efforts for the success of Gran Tierra and its affiliates.

(b) *Stock Subject to the Plan*

The maximum aggregate number of shares reserved for issuance under the Plan is 39,806,100 shares (the **"Share Reserve"**).

Under the terms of the Plan, the Share Reserve will be reduced by (i) one share for each share of Common Stock issued pursuant to an option or stock appreciation right, and (ii) 1.55 shares for each share of Common Stock issued pursuant to any other type of stock award, referred to as a "Full Value Award". If a stock award is settled in cash, such settlement will not reduce the Share Reserve.

The following shares of Common Stock granted pursuant to a stock award under the Plan will become available for subsequent issuance under the Plan as such shares become available from time to time, as follows:

- one share for each share subject to an outstanding option or stock appreciation right that expires, terminates for any reason prior to exercise or settlement or that is forfeited or otherwise returns because of the failure to meet a contingency or condition required to vest such shares;
- 1.55 shares for each share subject to a Full Value Award that is forfeited or otherwise returns because of the failure to meet a contingency or condition required to vest such shares or the Full Value Award otherwise terminates without all of the shares covered by the Full Value Award having been issued; and
- 1.55 shares for each share subject to a Full Value Award that is reacquired or withheld or not issued to satisfy a tax withholding obligation.

However, any shares of Common Stock granted pursuant to a stock award under the Plan or the Prior Plan that are not delivered to a participant because of any of the following reasons will not become available for subsequent issuance under the Plan:

- shares are not delivered to a participant because an option or stock appreciation right is exercised through a reduction in the number of shares subject to the stock award (a **"net exercise"**);

- shares are reacquired or withheld or not issued to satisfy a tax withholding obligation in connection with an option or stock appreciation right;

- shares are used as consideration for the exercise of an option or stock appreciation right; or

- shares are repurchased by Gran Tierra on the open market with the proceeds of an option or stock appreciation right exercise price.

(c) *Eligibility*

Employees (including officers), directors, and consultants of both Gran Tierra and its affiliates are eligible to receive all types of awards under the Plan. Under the Plan, no employee may be granted options or stock appreciation rights whose value is determined by reference to an increase over an exercise or strike price of at least 100% of the fair market value on the date of grant covering more than 1,000,000 (0.3%) shares of Common Stock during any calendar year. The maximum number of shares which may be reserved for issuance to insiders, at any time, under the Plan, and any other share compensation arrangement of Gran Tierra shall be 10% of the shares of Common Stock issued and outstanding. Additionally, the maximum number of shares of Common Stock which may be issued under the Plan, at any time, and any other share compensation arrangements within any 12-month period shall be 10% of the Common Stock outstanding for insiders as a group and 5% of the Common Stock outstanding for any one insider and such insider's associates. The maximum number of options that may be granted to any one consultant in any 12-month period shall not exceed 2% of the issued and outstanding Common Stock at the time of grant.

(d) *Repricing; Cancellation and Re-Grant of Stock Awards*

Under the Plan, the Board does not have the authority to reduce the exercise, purchase or strike price of an option or stock appreciation right or to cancel any outstanding option or stock appreciation right that has an exercise price greater than the current fair market value of the Common Stock in exchange for cash or other stock awards without obtaining the approval of Gran Tierra's stockholders within 12 months prior to the repricing or cancellation and re-grant event. Additionally, the Board may not reduce the exercise price of an option or extend the term of an option held by an insider without obtaining the approval of the stockholders other than insiders who are eligible to receive stock awards and such insiders' associates, at a meeting of the stockholders.

(e) *Terms of Options*

The following is a description of the permissible terms of options under the Plan. Individual option grants may be more restrictive as to any or all of the permissible terms described below.

(i) Exercise Price; Payment

The exercise price of options may not be less than 100% of the fair market value of the stock on the date of grant. The "fair market value" of the Common Stock on a particular day is generally the closing sales price for the Common Stock (or the closing bid, if no sales were reported) as quoted on the primary exchange or market upon which the common Stock trades. If that day is not a market trading day, then the last market trading day prior to the day of determination is used.

The exercise price of options granted under the Plan must be paid either in cash at the time the option is exercised or at the discretion of the Board, (i) by delivery of other common stock of Gran Tierra, (ii) by a "net exercise" arrangement, (iii) pursuant to a program developed under Regulation T as promulgated by the Federal Reserve Board that, prior to the issuance of common stock, results in either the receipt of cash (or check) by Gran Tierra or the receipt of irrevocable instructions to pay the aggregate exercise price to Gran Tierra from the sale proceeds, or (iv) in any other form of legal consideration acceptable to the Board.

(ii) Option Exercise

Options granted under the Plan may become exercisable in cumulative increments, or vest, as determined by the Board. Shares covered by currently outstanding options under the Plan typically vest over a three year period in three equal annual instalments during the participant's employment by, or service as a director or consultant to, Gran Tierra or an affiliate.

(iii) Term

The maximum term of options under the Plan is 10 years. Options under the Plan generally terminate three months after termination of the participant's service unless (A) such termination is due to the participant's permanent and total disability, in which case the option may, but need not, provide that it may be exercised (to the extent the option was exercisable at the time of the termination of service) at any time within 12 months of such termination; (B) the participant dies before the participant's service has terminated, or within three months after termination of such service, in which case the option may, but need not, provide that it may be exercised (to the extent the option was exercisable at the time of the participant's death) within 18 months of the participant's death by the person or persons to whom the rights to such option pass by will or by the laws of descent and distribution; or (C) the option by its terms specifically provides otherwise. A participant may designate a beneficiary who may exercise the option following the participant's death. Individual option grants by their terms may provide for exercise within a longer period of time following termination of service.

The option term generally may be extended in the event that exercise of the option within these periods is prohibited. A participant's option agreement may provide that if the exercise of the option following the termination of the participant's service would be prohibited because the issuance of stock would violate the registration requirements under the U.S. Securities Act, then the option will terminate on the earlier of (A) the expiration of the term of the option or (B) three months after the termination of the participant's service during which the exercise of the option would not be in violation of such registration requirements.

(iv) Restrictions On Transfer

The Board may grant stock options that are transferable to the extent provided in the stock option agreement. If an option does not provide for transferability then the option shall not be transferable except by will or by the laws of descent and distribution or pursuant to a domestic relations order and shall be exercisable during the lifetime of the option holder and only by the option holder. Shares subject to repurchase by Gran Tierra under an early exercise stock purchase agreement may be subject to restrictions on transfer that the Board deems appropriate.

(f) *Terms of Restricted Stock Awards and Purchases of Restricted Stock*

(i) Payment

The Board determines the purchase price under a restricted stock purchase agreement but the purchase price may not be less than the par value of the Common Stock on the date of purchase. The Board may award stock bonuses in consideration of past services without a purchase payment.

The purchase price of stock acquired pursuant to a restricted stock purchase agreement under the Plan must be paid either in cash at the time of purchase or at the discretion of the Board, (A) by cash at the time of purchase, (B) by services rendered, or to be rendered to Gran Tierra or (C) in any other form of legal consideration acceptable to the Board.

(ii) Vesting

Shares of stock sold or awarded under the Plan may, but need not be, subject to a repurchase option in favour of Gran Tierra in accordance with a vesting schedule as determined by the

Board. The Board has the power to accelerate the vesting of stock acquired pursuant to a restricted stock purchase agreement under the Plan in the event of death, disability, or in the event of a change in control.

(iii) Restrictions on Transfer

Rights under a stock bonus or restricted stock bonus agreement may be transferred only upon the terms and conditions of the award agreement as the Board shall determine in its discretion, except where such assignment is required by law or expressly authorised by the terms of the applicable stock bonus or restricted stock purchase agreement.

(g) *Other Stock Awards*

Other forms of stock awards valued in whole or in part with reference to or otherwise based on the Common Stock may be granted either alone or in addition to other stock awards under the Plan. The Board will have sole and complete authority to determine the persons to whom and the time or times at which such other stock awards will be granted, the number of shares of Common Stock (or the cash equivalent thereof) to be granted and all other conditions of such other stock awards. Other forms of stock awards may be subject to vesting in accordance with a vesting schedule to be determined by the Board. RSUs, including PSUs, are subject to a three year vesting period. Although DSUs vest immediately, directors are not eligible to receive payment until such time as they are no longer a director of the Company.

(h) *Adjustment Provisions*

Transactions not involving receipt of consideration by Gran Tierra, such as a merger, consolidation, reorganisation, stock dividend, or stock split, may change the type(s), class(es) and number of shares of common stock subject to the Plan and outstanding awards. In that event, the Plan will be appropriately adjusted as to the type(s), class(es) and the maximum number of shares of Common Stock subject to the Plan, and outstanding Awards will be adjusted as to the type(s), class(es), number of shares and price per share of Common Stock subject to such Awards.

(i) *Effect of Certain Corporate Transactions*

The Plan provides that in the event of the consummation of (i) the sale or other disposition of all or substantially all of the assets of Gran Tierra, (ii) the sale or other disposition of at least 50% of the outstanding securities of Gran Tierra, or (iii) certain specified types of merger, consolidation or similar transactions, or collectively, a corporate transaction, any surviving or acquiring corporation may continue or assume Awards outstanding under the Plan or may substitute similar Awards. Regardless of whether any surviving or acquiring corporation assumes such Awards or substitutes similar Awards, with respect to Awards held by participants whose service with Gran Tierra or an affiliate has not terminated as of the effective time of the corporate transaction, the vesting of such awards (and, if applicable, the time during which such awards may be exercised) will be accelerated in full.

(j) *Duration, Amendment and Termination*

The Board may suspend or terminate the Plan without stockholder approval or ratification at any time or from time to time.

The Board may at any time, or from time to time, amend or revise the Plan as follows: (a) to make amendments to the Plan or a Stock Award of a housekeeping or administrative nature; (b) if the Common Stock is listed on the TSX subject to any required approval of the TSX, to change the vesting or termination provisions of a Stock Award or the Plan; (c) amendments necessary to comply with provisions of applicable law or stock exchange requirements or for grants to qualify for favourable treatment under applicable laws; and (d) any other amendment, fundamental or otherwise, not requiring stockholder approval under the IRS Code. However, no amendment will be effective unless approved by the stockholders of Gran Tierra within 12 months before or after its adoption by the Board to the extent such approval is necessary to satisfy the requirements of Section 422 of the IRS Code. The Board may submit any other amendment to the Plan for stockholder approval.

For so long as Gran Tierra's stock is listed on the TSX, under the rules and policies of the TSX any amendment to the Plan is subject to pre-clearance of such amendment by the TSX, and no amendment, suspension or discontinuance of the Plan may contravene the requirements of the TSX.

7.2 Performance Stock Units

Performance Stock Units (**"PSUs"**) entitle the holder to receive, at the option of the Company, either the underlying number of shares of 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 continued employment of the grantee. The number of PSUs that vest may range from zero to 200% of the target number granted based on the Company's performance with respect to the applicable performance targets.

The performance targets for the PSUs outstanding as at December 31, 2017, were as follows:

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

(b) 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; and

(c) 25% of the award is subject to targets relating to the execution of corporate strategy.

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. PSUs in excess of the target number granted will vest and be settled if performance exceeds the targeted performance goals. The Company currently intends to settle the PSUs in cash.

7.3 Deferred Stock Units and Restricted Stock Units

Deferred Stock Units (**"DSUs"**) and Restricted Stock Units (**"RSUs"**) entitle the holder to receive, either the underlying number of shares of 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. The Company's historic practice has been to settle RSUs in cash and the Company currently intends to settle the RSUs and DSUs outstanding as at 31 December 2017 in cash, and, therefore, DSUs and RSUs are accounted for as liability instruments. Once a DSU or RSU is vested, it is immediately settled. During the year ended 31 December 2017, DSUs were granted to directors and will vest 100% at such time the grantee ceases to be a member of the Board.

7.4 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. Stock options generally vest over three years. The term of stock options granted starting in May 2013 is five years or three months after the grantee's end of service to the Company, whichever occurs first. Stock options granted prior to May 2013 continue to have a term of ten years or three months after the end of the grantee's service to the Company, whichever occurs first.

7.5 PSU, DSU, RSU and stock option activity

The following table provides information about PSU, DSU, RSU and stock option activity for the year ended 31 December 2017:

	PSUs	DSUs	RSUs	Stock Options	
	Number of Outstanding Share Units	Number of Outstanding Share Units	Number of Outstanding Share Units	Number of Outstanding Stock Options	Weighted Average Exercise Price /Stock Option ($)
Balance, 31 December 2016	3,362,717	208,698	359,145	9,239,478	$4.16
Granted	3,422,170	247,070	—	2,029,035	$2.54
Exercised	—	—	(224,548)	—	—
Forfeited	(652,936)	—	(12,507)	(911,154)	(4.79)
Expired	—	—	—	(1,396,667)	(4.65)
Balance, 31 December 2017	6,131,951	455,768	122,090	8,960,692	$3.65
Exercisable, at 31 December 2017				5,044,267	$4.33
Vested, or expected to vest, at 31 December 2017, through the life of the options				8,792,816	$3.67

8. PENSIONS

The Group does not have any pension plans for its Directors, officers or employees. The Group did not accrue or set aside any amounts to provide pension, retirement or similar benefits to the Directors and Senior Management for the year ended 31 December 2017.

9. MANDATORY BIDS AND COMPULSORY ACQUISITION RULES RELATING TO THE COMMON STOCK

As the Company is incorporated under the laws of a state of the United States, the City Code on Takeovers and Mergers of the United Kingdom will not apply to the Company, and a takeover offer by the Company will not be regulated by the Panel on Takeovers and Mergers.

The Company is a Delaware corporation and is subject to the DGCL. Section 253 of the DGCL permits a parent corporation that owns at least 90 per cent of the outstanding shares of each class of the stock of a Delaware corporation to merge the subsidiary corporation with and into the parent corporation without the approval of such subsidiary's stockholders. Section 262 of DGCL provides minority stockholders with appraisal rights and generally permits stockholders who dissent from the stockholder approval for a merger, if such approval is required for the merger, to request an appraisal of the fair value of their stock from the Delaware Chancery Court. A stockholder is accordingly entitled to dissent from, and request payment of the fair value of such stockholder's share in the event of, among other things, a merger or consolidation, in each case requiring stockholder approval. Notwithstanding the foregoing, the DGCL does not confer appraisal rights on a stockholder receiving shares that are either (i) listed on a national securities exchange or (ii) held of record by more than 2,000 holders, provided that the consideration received by such stockholder in the merger or consolidation for which such stockholder is seeking appraisal consists solely of the stock of the acquiring corporation.

10. MATERIAL CONTRACTS

The following are all of the contracts, not being contracts entered into in the ordinary course of business, that have been entered into by the Company since its incorporation and are, or may be, material or that contain any provision under which the Company has any obligation or entitlement which is or may be material to the Company as at the date of this Prospectus.

10.1 Revolving Credit Facility

The Company, Gran Tierra Energy International Holdings Ltd (**"GTEIH"**), certain subsidiaries of the Company and a group of lenders are parties to a revolving credit facility agreement dated 18 September 2015, and as amended from time to time thereafter (the **"Revolving Credit Facility"**). Availability under the revolving credit facility is determined by a reserves-based borrowing base, and remains subject to the satisfaction of conditions precedent set forth in the credit agreement. Loans under the credit agreement are scheduled to mature on 10 November 2020. The borrowing base is currently $300 million and will be re-determined semi-annually based on reserve evaluation reports, subject to a maximum of $500 million. The borrowing base for the Revolving Credit Facility is supported by the present value of the petroleum reserves of Gran Tierra's subsidiaries with operating branches in Colombia. The credit agreement includes a letter of credit sub-limit of up to $100 million. Amounts drawn down under the facility bear interest, at the option of the Company, at the USD LIBOR rate plus a margin ranging from 2.15% and 3.65% per annum, or an alternate base rate plus a margin ranging from 1.15% per annum to 2.65% per annum, and undrawn amounts bear interest at a rate of 0.5375% to 0.9125%, in each case based on the ratio of Senior Secured Obligations to EBITDAX (as defined in the credit agreement). A letter of credit participation fee of 0.25% per annum will accrue on the average daily amount of letter of credit exposure.

In connection with the entry into the revolving credit facility, and as a condition precedent to borrowing loans thereunder, Gran Tierra and certain of Gran Tierra's other direct and indirect subsidiaries entered into certain ancillary agreements, including but not limited to:

- a guaranty and collateral agreement governed by New York law made by GTEIH, Gran Tierra, Gran Tierra Callco ULC, Gran Tierra Exchangeco Inc., 1203647 Alberta Inc., Gran Tierra Goldstrike Inc., Gran Tierra Resources Limited (f/k/a Solana Resources Limited), Petrolifera Petroleum (Colombia) Limited, Gran Tierra Energy Cayman Islands Inc., Gran Tierra Energy Colombia, Ltd., Argosy Energy, LLC, and Gran Tierra Energy Canada ULC in favour of the administrative agent;

- an equitable share mortgage governed by the laws of the Cayman Islands over the shares of GTEIH and share mortgages governed by the laws of the Cayman Islands over the shares of Petrolifera Petroleum (Colombia) Limited and Gran Tierra Energy Cayman Islands Inc.;

- a general security agreement governed by the laws of the Province of Alberta and the law of Canada executed and delivered by each of Gran Tierra Resources Limited, Gran Tierra, Gran Tierra Exchangeco Inc., Gran Tierra Callco ULC, 1203647 Alberta Inc., Gran Tierra Goldstrike Inc., and Gran Tierra Energy Canada ULC in favour of the administrative agent; and

- securities pledges governed by the laws of the Province of Alberta and the laws of Canada executed by Gran Tierra respecting all of the shares in Gran Tierra Callco ULC and 1203647 Alberta Inc., Gran Tierra Goldstrike Inc. respecting all of the shares in Gran Tierra Resources Limited, Gran Tierra Exchangeco Inc. respecting all of the shares in Gran Tierra Resources Limited, Gran Tierra Callco ULC respecting all of the shares in Gran Tierra Exchangeco Inc., Gran Tierra Energy Cayman Islands Inc. respecting all of the shares in Gran Tierra Energy Canada ULC, 1203647 Alberta Inc. respecting all of the shares in Gran Tierra Goldstrike Inc.

Under the terms of the Revolving Credit Facility, Gran Tierra is required to maintain compliance with certain financial and operating covenants which include: the maintenance of a ratio of debt, including letters of credit, to net income plus interest, taxes, depreciation, depletion, amortisation, exploration expenses, and all other noncash charges, minus all noncash income (**"EBITDAX"**) not to exceed 4.00 to 1.00; the maintenance of a ratio of Senior Secured Obligations to EBITDAX not to exceed 3.00 to 1.00; and the maintenance of a ratio of EBITDAX to interest expense of at least 2.5 to 1.0. The covenants also include restrictions on, among other things, subject to exceptions and thresholds: the incurrence of debt and liens; the making of restricted payments and investments; changes in the nature of the business of the Company; incurrence of leases; use of loan proceeds; sales or discount of receivables; mergers; dispositions of properties; environmental matters; transactions with affiliates; entry into restrictive agreements; entry into swap agreements; amendment or other modifications of material documents; marketing activities; and violations of sanctions and anti-corruption laws. As at 30 June 2018, Gran Tierra was in compliance with all financial and operating covenants in the credit agreement. As of 30 June 2018, no amount has been drawn on this facility. The Revolving Credit Facility replaced the Group's previous credit facility, which was cancelled on 18 September 2015. The Revolving Credit Facility contains events of default that are usual and customary for a financing of this type, size and purpose including, among others, subject to applicable grace periods and materiality thresholds, non-payment of principal, interest or fees, violation of covenants, material inaccuracy of representations and warranties, bankruptcy and insolvency events, cross-payment default and cross-accelerations, certain judgments, certain governmental actions regarding property and taxation, defaults under certain concession agreements or offtake agreements, and events constituting a change of control.

10.2 **5.00% Convertible Senior Notes due 2021**

On 6 April 2016, Gran Tierra issued $100 million aggregate principal amount of Convertible Notes in a private placement to qualified institutional buyers. On 22 April 2016, Gran Tierra issued an additional $15 million aggregate principal amount of the Convertible Notes pursuant to the underwriters' exercise of their option to acquire additional convertible notes. The convertible notes bear interest at a rate of 5.00% per year, payable semi-annually in arrears on 1 April and 1 October of each year, beginning on 1 October 2016. The Convertible Notes will mature on 1 April 2021, unless earlier redeemed, repurchased or converted. The Convertible Notes are unsecured and are subordinated to secured debt to the extent of the value of the assets securing such indebtedness.

The Convertible Notes are convertible at the option of the holder at any time prior to the close of business on the business day immediately preceding the maturity date. The conversion rate is initially 311.4295 shares of the Common Stock per $1,000 principal amount of Convertible Notes (equivalent to an initial conversion price of approximately $3.21 per share of the Common Stock). The conversion rate is subject to adjustment in some events but will not be adjusted for any accrued and unpaid interest. In addition, following certain corporate events that occur prior to the maturity date, Gran Tierra will increase the conversion rate for a holder who elects to convert its Convertible Notes in connection with such a corporate event in certain circumstances.

Gran Tierra may not redeem the convertible notes prior to 5 April 2019, except in certain circumstances following a fundamental change (as defined in the indenture governing the convertible notes). Gran Tierra may redeem for cash all or any portion of the convertible notes, at its option, on or after 5 April 2019, if (terms below are as defined in the indenture governing the convertible notes):

(a) the last reported sale price of Gran Tierra's common stock has been at least 150% of the conversion price then in effect for at least 20 trading days (whether or not consecutive) during any 30 consecutive trading day period (including the last trading day of such period) ending on, and including, the trading day immediately preceding the date on which Gran Tierra provide notice of redemption; and

(b) Gran Tierra has filed all reports that it was required to file with the SEC pursuant to Section 13 or 15(d) of the Exchange Act, as applicable (other than current reports on Form 8-K), during the twelve months preceding the date on which it provides such notice.

The redemption price will be equal to 100% of the principal amount of the Convertible Notes to be redeemed, plus accrued and unpaid interest, if any, to, but excluding, the redemption date. No sinking fund is provided for the Convertible Notes.

If Gran Tierra undergoes a fundamental change, holders may require Gran Tierra to repurchase for cash all or any portion of their Convertible Notes at a fundamental change repurchase price equal to 100% of the principal amount of the Convertible Notes to be repurchased, plus accrued and unpaid interest to, but excluding, the fundamental change repurchase date.

10.3 **6.25% Senior Notes due 2025**

On 15 February 2018, GTEIH, an indirect, wholly owned subsidiary of the Company, issued $300 million of 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. Net proceeds from the sale of the Senior Notes were $288.1 million, after deducting the initial purchasers' discounts and commission and the offering expenses payable by the Company.

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

Before 15 February 2022, GTEIH may, at its option, redeem all or a portion of the 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 Senior Notes plus accrued and unpaid interest applicable to the date of the redemption at the following redemption prices:

Year	**Redemption price (% of principal amount)**
2022	103.125%
2023	101.563%
2024 and thereafter	100%

10.4 **Share purchase agreement relating to the Peru Business Unit**

Pursuant to a share purchase agreement dated 9 November 2017 (the **"Peru SPA"**) between the Company, GTEIH, PetroTal Ltd and Sterling Resources Ltd, GTEIH agreed to sell all of the issued and outstanding shares of Gran Tierra Energy International Peru Holdings B.V. (**"GTEIPH"**) (the **"Peru Transaction"**).

In connection with the Peru Transaction, PetroTal Ltd. and Sterling Resources Ltd. had entered into an arrangement agreement under which, among other things, PetroTal Ltd. would complete a reverse takeover of Sterling Resources Ltd., PetroTal Ltd. and Sterling Resources Ltd. would be amalgamated into a single entity and such resulting entity, PetroTal Corp. (referred to in this paragraph 10.4 as the **"Resulting Issuer"**), would purchase all of the issued and outstanding shares of GTEIPH.

Completion of the Peru Transaction was conditional upon, among other matters, the completion of a minimum $25 million equity financing by PetroTal Ltd., approval by the TSX Venture Exchange (**"TSXV"**) of, among other matters, the reverse takeover of Sterling Resources Ltd. and the listing of the Resulting Issuer's shares on the TSXV, certain minimum working capital levels of PetroTal Ltd. and Sterling Resources Ltd. and other regulatory and customary conditions.

The Peru Transaction completed on 18 December 2017 for an aggregate consideration of $33.5 million, comprised of approximately 187,250,000 common shares of the Resulting Issuer and an estimated cash-settled working capital adjustment of $0.4 million.

Pursuant to the terms of the Peru SPA, GTEIH also entered into certain ancillary agreements, including:

- an investor rights agreement with Gran Tierra Resources Limited (**"GTRL"**) and the Resulting Issuer pursuant to which GTEIH and GTRL together would have the right to nominate two directors to the board of the Resulting Issuer, as well as certain demand and piggy-back registration rights and pre-emption rights. The investor rights agreement prohibits GTEIH and GTRL from exercising voting rights over more than 30% of the issued and outstanding common shares of the Resulting Issuer;

- a carried interest and option agreement with the Resulting Issuer and a Peruvian subsidiary pursuant to which GTEIH has a 20% carried working interest in Block 107, located in the

Ucayali basin in Peru, which interest will, at the option of GTEIH, either be converted to a non-carried working interest or be forfeited following the drilling of an exploration well in Block 107; and

- an escrow agreement, substantially in the form required by the TSXV, in respect of 90% of the share consideration and pursuant to which the shares under escrow would be released from escrow at 15% every six months for a period of 36 months following 18 December 2017.

Additionally in connection with the Peru Transaction, Gran Tierra purchased $11.0 million of subscription receipts which were exchangeable for common shares of PetroTal Ltd., and subsequently exchanged for approximately 58.9 million common shares of the Resulting Issuer. After giving effect to the Peru Transaction, Gran Tierra directly and indirectly holds approximately 246.1 million common shares of the Resulting Issuer, representing approximately 46% of the Resulting Issuer's issued and outstanding common shares.

10.5 Sale and Purchase Agreement in respect of Brazil assets

Pursuant to a share and loan purchase agreement dated 5 February 2017, as subsequently amended (the **"Brazil SPA"**), between GTEIH, Gran Tierra Luxembourg Holdings S.À.R.L (**"Gran Tierra Luxembourg"**) and Maha Energy AB (**"Maha"**), Maha agreed to purchase all of the Group's assets in Brazil at the time through the acquisition by Maha of all of the equity interests of Gran Tierra Luxembourg and the assignment to Maha of certain debts owed by the corporate entities comprising the Brazil business unit to other members of the Group (the **"Brazil Transaction"**).

Completion of the Brazil Transaction was conditional upon, among other matters, the receipt of regulatory approval from the Agência Nacional do Petróleo, Gás Natural e Biocombustíveis of Brazil and to Maha obtaining relevant financing. Pursuant to the terms of the Brazil SPA, Maha was required to pay an initial deposit of $3.5 million, which was not refundable in certain circumstances, including in the event Maha was not successful in obtaining the relevant financing to complete the Brazil Transaction.

The Brazil Transaction completed on 30 June 2017 for a purchase price of $35.0 million, which, after certain final closing adjustments, resulted in cash consideration of approximately $36.8 million. In addition to the cash consideration, Maha also agreed to assume certain existing and potential liabilities of the Brazil business unit.

11. RELATED PARTY TRANSACTIONS

Gran Tierra discourages transactions with related parties. There were no related party transactions entered into by Gran Tierra between 1 January 2014 and the date of this Prospectus that were, or would be, required to be disclosed in the Group's Consolidated Financial Statements.

12. LITIGATION

The Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) (**"ANH"**) and Gran Tierra are engaged in discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the HPR royalty. These discussions began in the over six years ago and remain ongoing. No formal court proceedings have been commenced in relation to this matter. Based on Gran Tierra's understanding of the ANH's position, the estimated compensation, which would be payable if the ANH's interpretation is correct, could be up to $52.8 million as at 30 June 2018. At this time, no amount has been accrued in the financial statements as Gran Tierra does not consider it probable that a loss will be incurred.

Save as disclosed above, there are no, and have not been, any governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which the Company is aware), which may have, or have had, during the 12 months preceding the date of this Prospectus, a significant effect on the Group's financial position or profitability.

13. **SIGNIFICANT CHANGE**

There has been no significant change in the Group's financial or trading position since 30 June 2018, being the latest date to which the Company's historical financial information in Appendix 1 (*Historical Financial Information*) was prepared.

14. **WORKING CAPITAL STATEMENT**

In the opinion of the Company, the working capital available to the Group is sufficient for its present requirements, that is, for at least the next 12 months from the date of this Prospectus.

15. **FACILITIES**

Details of the Group's main leased properties, and any material encumbrances thereon, are set out in the table below.

Location	**Tenure**	**Purpose**	**Term Expiry Date**
Calgary Office Suite 900, 520 – 3rd Avenue SW Calgary, Alberta, Canada, T2P 0R3	6 years, 2 months (commencing 1 October 2016)	Head Office	29 November 2022
Bogota Office Calle 113 No.7 – 80, 17th Floor Bogota D.C. Colombia Floors 17, 16, and 15 (West)	5 years (commencing 1 March 2016)	Colombia Head Office	28 February 2021
Bogota Office Calle 113 No.7 – 80, 17th Floor Bogota D.C. Colombia Floor 15 (East)	4 years, 6 months (commencing 1 September 2016)	Colombia Head Office	28 February 2021

16. **DEALING ARRANGEMENTS**

Applications have been made to the FCA for all of the shares of Common Stock to be admitted to listing on the standard listing segment of the Official List of the FCA and to the London Stock Exchange for such shares of Common Stock to be admitted to trading on the London Stock Exchange's main market for listed securities. It is expected that dealings in the Common Stock will commence at 8.00 a.m. on 10 October 2018. On Admission, the shares of Common Stock will be registered with ISIN US38500T1016 and SEDOL number B09R9V5. The Company's ticker symbol will be "GTE".

The shares of Common Stock are currently admitted to trading on the NYSE American and on the TSX and, following Admission, will continue to be listed on the NYSE American and on the TSX in each case under the ticker symbol "GTE".

17. **CONSENT**

McDaniel & Associates Consultants Ltd. has given and has not withdrawn its consent to the inclusion in this Prospectus of the Competent Person's Report set out in Appendix 2 (*Competent Person's Report*), and the references thereto and to its name, in the form and context in which they are included and have authorised the contents of that part of this Prospectus which comprises their report for the purposes of paragraph 5.5.3R(2)(f) of the Prospectus Rules.

18. **GENERAL**

18.1 The information set out in this Prospectus that has been sourced from third parties has been accurately reproduced and, so far as the Company is aware and is able to ascertain from information published by that third party, no facts have been omitted which would render the reproduced information inaccurate or misleading. Where third-party information has been used in this Prospectus, the source of such information has been identified.

18.2 Deloitte LLP, Chartered Professional Accountants, who are registered with the Canadian Public Accountability Board and the Public Company Accounting Oversight Board (United States), and whose address is at 700, 850–2nd Street SW, Calgary, Alberta Canada T2P 0R8 acted as auditor to the Group in respect of each of the financial years ended 31 December 2015, 2016 and 2017. On 12 March 2018, the Audit Committee of the Board approved the dismissal of Deloitte LLP as the Company's independent registered public accounting firm. There were no disagreements between the Company and Deloitte and no reportable events. Deloitte's reports on the Company's consolidated financial statements as at December 31, 2017 and December 31, 2016 and for the three-year ended December 31, 2017, and the consolidated financial statements as at December 31, 2016 and December 31, 2015 and for the three-year ended December 31, 2016 did not contain an adverse opinion or a disclaimer of opinion and were not qualified or modified as to uncertainty, audit scope, or accounting principles.

18.3 KPMG LLP, Chartered Professional Accountants, who are registered with the Canadian Public Accountability Board and the Public Company Accounting Oversight Board (United States), and whose address is at 3100-205 5th Avenue SW, Calgary, Alberta, Canada, act as auditor to the Group in respect of the financial year ending 31 December 2018. KPMG LLP was formally engaged on 12 March 2018.

19. **DOCUMENTS AVAILABLE FOR INSPECTION**

19.1 Copies of the following documents will be available for inspection at the principal place of business of the Company during normal business hours on any weekday (Saturdays, Sundays and public holidays excepted) for a period of 12 months from the date of publication of this Prospectus:

(a) the Bylaws;

(b) the Company's consolidated financial statements as at 31 December 2017 and 31 December 2016 and for the three years ended 31 December 2017, together with the auditor's report thereon, which are set out in Appendix 1 (*Historical Financial Information*);

(c) the Company's consolidated financial statements as at 31 December 2016 and 31 December 2015 and for the three years ended 31 December 2016, together with the auditor's report thereon, which are set out in Appendix 1 (*Historical Financial Information*);

(d) the consent letter referred to in paragraph 17 of this Part VII (*Additional Information*); and

(e) this Prospectus.

19.2 Copies of this Prospectus are also available for inspection at the National Storage Mechanism at www.morningstar.co.uk/uk/nsm.

PART VIII – CREST DEPOSITARY INTERESTS

1. CREST AND DEPOSITARY ARRANGEMENTS

CREST is a paperless settlement system allowing securities to be transferred from one person's CREST account to another without the need to use share certificates or written instruments of transfer. Securities issued by non-UK companies, such as the Company, cannot be held or transferred electronically in the CREST system. However, depositary interests allow such securities to be dematerialised and settled electronically through CREST. Investors who choose to settle interests in the Common Stock through the CREST system will be issued with dematerialised CDIs representing entitlements to shares of Common Stock. One CDI will represent one share of Common Stock. While holders of CDIs will have an interest in the underlying shares of Common Stock, they will not be the registered holders of the shares of Common Stock.

The CDIs will be delivered, held and settled in CREST and linked to the underlying shares of Common Stock by means of the CREST International Settlement Links Service and, in particular, the established link with DTC. This link operates via the services of CREST International Nominees Limited (acting as custodian for Euroclear UK & Ireland Limited (**"Euroclear"**)), which is a participant in Depository Trust Company (the **"DTC"**), the US settlement and clearance system. Under the CREST International Settlement Links Services, CREST Depository Limited, a subsidiary of Euroclear, issues dematerialised depository interests representing entitlements to non-UK securities (such as shares of Common Stock) called CDIs, which may be held, transferred and settled exclusively through the CREST system.

The terms on which CDIs are issued and held in CREST are set out in the CREST Manual (and, in particular, the deed poll set out in the CREST International Manual) and the CREST Terms and Conditions issued by Euroclear. A custody fee, as determined by CREST from time to time, is charged at the user level (i.e. to the holder of CDIs) for the CREST International Settlement Links Service.

2. RIGHTS ATTACHING TO CDIS

The registered holder of shares of Common Stock represented by CDIs will be Cede & Co, a nominee of DTC. The custodian of the shares of Common Stock will be CREST International Nominees Limited, who will hold them through DTC either directly or through a sub-custodian as nominee for CREST Depository Limited. CREST Depository Limited will hold those shares of Common Stock on trust (as bare trustee under English law) for the shareholders who elect to hold their interests in the Common Stock in uncertificated form through the CREST system, to whom it will issue CDIs.

Holders of CDIs will be able to cancel their CDIs by settling a cross-border delivery transaction in respect of the underlying shares of Common Stock through CREST to a DTC participant, in accordance with the rules and practices of CREST and DTC. Transaction fees will be payable by a holder of CDIs who executes a transaction through CREST (including a cancellation of CDIs).

Accordingly, the holders of CDIs will only be able to exercise rights relating to shares of Common Stock in accordance with the arrangements described below.

In order to allow the holders of CDIs to exercise rights relating to the underlying shares of Common Stock, the Company will enter into arrangements pursuant to which holders of CDIs will be able to:

(a) receive notices of general shareholder meetings of the Company;

(b) give directions as to voting at general shareholder meetings of the Company; and

(c) have made available to them and be sent, at their request, copies of the annual report and accounts of the Company and all other documents issued by the Company to its shareholders generally.

Holders of CDIs will otherwise be treated in the same manner as if they were registered holders of the shares of Common Stock underlying their CDIs, in each case in accordance with applicable law and, so far as is possible, in accordance with CREST arrangements.

Under an agreement for the provision of the CDI register, Euroclear will make a copy of the register of the names and addresses of CDI holders available to the Company (or its agent) to enable the Company (or its agent) to: (a) send out notices of shareholder meetings and proxy forms to its CDI holders; and (b) produce a definitive list of CDI holders as at the relevant record date for the meeting.

In addition, Cede & Co and Euroclear have omnibus proxy arrangements pursuant to which CREST International Nominees Limited (the custodian of the shares of Common Stock underlying the CDIs) will be able to grant each CDI holder the right to vote in respect of such holder's underlying shares of Common Stock. As a result, the custodian and the depository step out of the voting arrangements and simply pass on any voting rights they have, by virtue of holding the underlying shares of Common Stock, to the CDI holders.

3. DEPOSITARY INTEREST FACILITY

The Company intends to establish a depositary interest facility with a third party depositary as soon as practicable following Admission. Pursuant to these arrangements, Depositary Interests representing shares of Common Stock will be issued and held on trust for holders of the Depositary Interests by such third party depositary. The Depositary Interests will be independent securities constituted under English law which may be held and transferred through the CREST system. It is expected that the depositary will, so far as it is reasonably able to, pass on to holders of the Depositary Interests all rights and entitlements received or to which they are entitled in respect of the underlying shares of Common Stock which are capable of being passed on or exercised. Once the depositary interest facility is set up, the CDIs will be cancelled and transferred to the third party depositary, who will issue holders of CDIs at the time of cancellation Depositary Interests in respect of their underlying holding of shares of Common Stock.

PART IX – DEFINITIONS

The following definitions will apply throughout this Prospectus unless the context otherwise requires.

"£" or **"pounds sterling"**	the lawful currency of the United Kingdom;
"Acordionero Field"	the Acordionero field as described in paragraph 2.1(a) of Part 1 (*Information on Gran Tierra*) of this Prospectus;
"Admission"	admission of the Common Stock to the standard listing segment of the Official List and to trading on the London Stock Exchange's main market for listed securities;
"ANH"	the Agencia Nacional de Hidrocarburos;
"Board" or **"Directors"**	the directors of the Company as at the date of this Prospectus and whose names are set out in Part II (*Directors, Senior Management and Corporate Governance*);
"Business Day"	a day on which the London Stock Exchange and banks in London are normally open for business;
"Bylaws"	the Company's bylaws, as further described in paragraph 5 of Part VII (*Additional Information*);
"CDIs"	CREST depositary interests;
"Certificate of Incorporation"	the Company's certificate of incorporation, as further described in paragraph 5 of Part VII (*Additional Information*);
"certificated" or **"certificated form"**	not uncertificated or in uncertificated form;
"City Code"	the City Code on Takeovers and Mergers of the United Kingdom;
"Common Stock"	the Company's common stock, par value of $0.001 per share;
"Company" or **"Gran Tierra"**	Gran Tierra Energy Inc, a Delaware corporation with registered number 6198266;
"Competent Person's Report"	the competent person's report relating to Gran Tierra's assets, as set out in Appendix 2 (*Competent Person's Report*);
"Convertible Notes"	the 5.00% Convertible Senior Notes due 2021 issued by the Company, as further described in paragraph 10.2 of Part VII (*Additional Information*);
"Corporate Governance Code"	the UK Corporate Governance Code as published by the Financial Reporting Council;
"Costayaco Field"	the Costayaco field as described in paragraph 2.1(b) of Part I (*Information on Gran Tierra*) of this Prospectus;

"CREST"	the facilities and procedures for the time being of the relevant system of which Euroclear has been approved as "Operator" pursuant to the CREST Regulations;
"CREST Regulations"	the UK Uncertificated Securities Regulations 2001 (SI 2001 No. 200l/3755);
"DD&A"	depletion, depreciation and accretion;
"Depositary Interests"	dematerialised depositary interests representing shares of Common Stock, to be issued by a third party depositary;
"DGCL"	the General Corporation Law of the State of Delaware, as amended from time to time;
"Disclosure Guidance and Transparency Rules"	the disclosure guidance and the transparency rules made under Part VI of FSMA;
"DSUs"	deferred share units;
"DTC"	Depository Trust Company, the US settlement and clearance system;
"EEA"	the European Economic Area;
"Euroclear"	Euroclear UK and Ireland Limited;
"FCA"	the UK Financial Conduct Authority (or its successor bodies);
"FSMA"	the Financial Services and Markets Act 2000, as amended;
"G&A"	general and administrative;
"Group"	the Company and its subsidiary undertakings;
"GTEIH"	Gran Tierra Energy International Holdings Ltd;
"HMRC"	HM Revenue and Customs of the United Kingdom;
"IRS"	the United States Internal Revenue Service;
"IRS Code"	the United States Internal Revenue Code of 1986;
"ISIN"	International Securities Identification Number;
"Latest Practicable Date"	26 September 2018, being the latest practicable date prior to the publication of this Prospectus;
"Listing Rules"	the listing rules made by the UK Listing Authority under section 73A of FSMA;
"London Stock Exchange"	the London Stock Exchange plc;
"MAR"	Regulation (EU) 596/2014 of the European Parliament and the Council of 16 April 2014 on market abuse and its delegated and implementing regulations;

"MMV"	the Middle Magdalena Valley;
"MMV Basin"	the Middle Magdalena Valley Basin;
"Moqueta Field"	the Moqueta field as described in paragraph 2.1(c) of Part I (*Information on Gran Tierra*) of this Prospectus;
"NEO"	named executive officer;
"NPV10 BT"	net present value discounted at 10% before tax;
"NYSE American"	the New York Stock Exchange American;
"Official List"	the list maintained by the UK Listing Authority pursuant to Part VI of FSMA;
"Petroamerica"	Petroamerica Oil Corp.;
"PetroLatina"	PetroLatina Energy Limited;
"PetroTal"	PetroTal Corp.;
"PGC"	PetroGranada Colombia Limited;
"Prospectus"	this Prospectus;
"Prospectus Directive"	Directive 2003/71/EC as amended and including any relevant implementing measure in each Relevant Member State;
"Prospectus Rules"	the Prospectus Rules made by the UK Listing Authority under section 73A of FSMA;
"PSUs"	performance stock units;
"RBC Capital Markets"	RBC Europe Limited, trading as RBC Capital Markets;
"Relevant Member State"	a member state of the EEA which has implemented Directive 2003/71/EC;
"Revolving Credit Facility"	the revolving credit facility dated 18 September 2015 between, among others, the Company, GTEIH and certain subsidiaries of the Company, as further described in paragraph 10.1 of Part VII (*Additional Information*);
"RIS" or **"Regulatory Information Service"**	one of the regulatory information services authorised by the FCA to receive, process and disseminate regulated information from listed companies;
"RSU"	restricted stock units
"SDRT"	UK stamp duty and stamp duty reserve tax;
"SEC"	the United States Securities and Exchange Commission;

"SEDI"	the System for Electronic Disclosure by Insiders, an online service for the filing and viewing of insider reports in Canada;
"Senior Management"	the members of the senior management team of the Company as at the date of this Prospectus, whose names are set out in Part II (*Directors, Senior Management and Corporate Governance*);
"Senior Notes"	the 6.25% Senior Notes due 2025 issued by GTEIH, as further described in paragraph 10.3 of Part VII (*Additional Information*);
"Shareholder"	a registered holder of a share of Common Stock;
"TSX"	Toronto Stock Exchange;
"uncertificated" or **"in uncertificated form"**	recorded on the register of members as being held in uncertificated form in CREST and title to which may be transferred by means of CREST;
"United Kingdom"	the United Kingdom of Great Britain and Northern Ireland;
"United States" or **"U.S."**	the United States of America, its territories and possessions, any state of the United States and the District of Columbia;
"US Securities Act"	the US Securities Act of 1933, as amended;
"VAT"	value added tax; and
"Voting Stock"	the outstanding shares of Common Stock entitled to vote generally in the election of directors.

PART X – GLOSSARY OF TECHNICAL TERMS

"API"	American Petroleum Institute
"bbl"	barrel;
"Bcf"	billion cubic feet;
"BOE"	barrels of oil equivalent;
"BOEPD"	barrels of oil equivalent per day;
"bfpd"	barrels of fluid per day;
"bopd"	barrels of oil per day;
"bwpd"	barrels of water per day;
"COGEH"	the Canadian Oil and Gas Evaluation Handbook maintained by The Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time;
"economic limit"	the earlier of (a) the date when a field no longer generates operating income in excess of its operating and capital expenses and (b) the expiry of the contract or licence governing the field;
"ESP"	electronic submersible pump;
"F&D costs"	finding and development costs, which costs are calculated as estimated exploration and development capital expenditures in Colombia, excluding acquisitions and dispositions, divided by the applicable reserves additions both before and after changes in FDC. The calculation of F&D costs incorporates the change in FDC required to bring proved undeveloped and developed reserves into production. The aggregate of the exploration and development costs incurred in the financial year and the changes during that year in estimated FDC may not reflect the total F&D costs related to reserves additions for that year. Management uses F&D costs per BOE as a measure of its ability to execute its capital program and of its asset quality;
"FDC"	future development costs;
"Mbbl"	thousand barrels;
"MBOE"	thousand barrels of oil equivalent;
"MMbbl"	million barrels;
"MMBOE"	million barrels of oil equivalent;
"MMcf"	million cubic feet;
"NAR"	net after royalty;

"wellhead"	all connections, valves, nozzles, pressure gauges and thermometers, installed at the exits from a production well;
"WI"	working interest;
"WTI price"	"West Texas Intermediate price"
"1P" or **"proved reserves"**	those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves;
"2P" or **"probable reserves"**	those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves; and
"3P" or **"possible reserves"**	those additional reserves that are less certain to be recovered than Probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of proved plus probable plus possible reserves.

APPENDIX 1 – HISTORICAL FINANCIAL INFORMATION

Section A: Financial Statements for the year ended 31 December 2017

Report of Independent Registered Public Accounting Firm

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Gran Tierra Energy Inc. and subsidiaries (the "**Company**") as at December 31, 2017 and 2016, the related consolidated statements of operations, shareholders' equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "**financial statements**"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We have also 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, 2017, 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 27, 2018 expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's 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. Further, we are required to be independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and to fulfill our other ethical responsibilities in accordance with these requirements.

We conducted our audits in accordance with the standards of the PCAOB and Canadian generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the 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 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte LLP

Chartered Professional Accountants
Calgary, Canada

February 27, 2018

We have served as the Company's auditor since 2005

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

	Year Ended December 31,		
	2017	**2016**	**2015**
OIL AND NATURAL GAS SALES (NOTE 3)	**$ 421,734**	$ 289,269	$ 276,011
EXPENSES			
Operating	**109,869**	86,925	75,565
Transportation	**25,107**	31,776	40,204
Depletion, depreciation and accretion (Note 3)	**131,335**	139,535	176,386
Asset impairment (Notes 3 and 5)	**1,514**	616,649	323,918
General and administrative (Note 3)	**39,014**	33,218	32,353
Severance	**1,287**	1,319	8,990
Transaction	**—**	7,325	—
Equity tax (Note 9)	**1,224**	3,098	3,769
Foreign exchange loss (gain)	**2,067**	(1,469)	(17,242)
Financial instruments loss (Note 12)	**15,929**	10,279	2,027
Other gain	**—**	—	(502)
Interest expense (Notes 3 and 6)	**13,882**	14,145	—
	341,228	942,800	645,468
(LOSS) ON SALE OF BUSINESS UNITS (NOTE 3 and 5) AND GAIN ON ACQUISITION	**(44,385)**	929	—
INTEREST INCOME	**1,209**	2,368	1,369
INCOME (LOSS) BEFORE INCOME TAXES (NOTE 3)	**37,330**	(650,234)	(368,088)
INCOME TAX EXPENSE (RECOVERY)			
Current (Note 9)	**24,322**	20,122	15,383
Deferred (Note 9)	**44,716**	(204,791)	(115,442)
	69,038	(184,669)	(100,059)
NET LOSS AND COMPREHENSIVE LOSS	**$ (31,708)**	$ (465,565)	$ (268,029)
NET LOSS PER SHARE - BASIC AND DILUTED	**$ (0.08)**	$ (1.45)	$ (0.94)
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC AND DILUTED (Note 7)	***396,683,593***	*320,851,538*	*285,333,869*

(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,	
	2017	**2016**
ASSETS		
Current Assets		
Cash and cash equivalents (Note 13)	**$ 12,326**	$ 25,175
Restricted cash and cash equivalents (Notes 8 and 13)	**11,787**	8,322
Accounts receivable (Note 4)	**45,353**	45,698
Investment (Note 12)	**25,055**	—
Derivatives (Note 12)	**302**	578
Inventory	**7,075**	7,766
Taxes receivable	**40,831**	26,393
Prepaid taxes (Notes 2 and 9)	**—**	12,271
Other prepaids	**2,516**	5,482
Total Current Assets	**145,245**	131,685
Oil and Gas Properties (using the full cost method of accounting)		
Proved	**629,081**	412,319
Unproved	**464,948**	647,774
Total Oil and Gas Properties	**1,094,029**	1,060,093
Other capital assets	**5,195**	6,516
Total Property, Plant and Equipment (Notes 3 and 5)	**1,099,224**	1,066,609
Other Long-Term Assets		
Deferred tax assets (Note 2 and 9)	**57,310**	1,611
Prepaid taxes (Notes 2 and 9)	**—**	41,784
Investment (Note 12)	**19,147**	—
Other long-term assets (Note 13)	**6,112**	23,626
Goodwill (Note 3)	**102,581**	102,581
Total Other Long-Term Assets	**185,150**	169,602
Total Assets (Note 3)	**$ 1,429,619**	$ 1,367,896
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities (Note 10)	**$ 126,171**	$ 107,051
Derivatives (Note 12)	**21,151**	3,824
Taxes payable (Note 9)	**9,324**	38,939
Asset retirement obligation (Note 8)	**323**	5,215
Total Current Liabilities	**156,969**	155,029
Long-Term Liabilities		
Long-term debt (Notes 6 and 12)	**256,542**	197,083
Deferred tax liabilities (Note 2 and 9)	**28,417**	107,230
Asset retirement obligation (Note 8)	**31,241**	38,142
Other long-term liabilities	**20,115**	11,425
Total Long-Term Liabilities	**336,315**	353,880
Commitments and Contingencies (Note 11)		
Subsequent Event (Note 14)		
Shareholders' Equity		
Common Stock (Note 7) (385,191,042 and 390,807,194 shares of Common Stock and 6,111,665 and 8,199,894 exchangeable shares, par value $0.001 per share, issued and outstanding as at December 31, 2017 and December 31, 2016, respectively)	**10,295**	10,303
Additional paid in capital	**1,327,244**	1,342,656
Deficit	**(401,204)**	(493,972)
Total Shareholders' Equity	**936,335**	858,987
Total Liabilities and Shareholders' Equity	**$ 1,429,619**	$ 1,367,896

(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,		
	2017	**2016**	**2015**
Operating Activities			
Net loss	**$ (31,708)**	$ (465,565)	$ (268,029)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depletion, depreciation and accretion (Note 3)	**131,335**	139,535	176,386
Asset impairment (Notes 3 and 5)	**1,514**	616,649	323,918
Deferred tax expense (recovery) (Note 9)	**44,716**	(204,791)	(115,442)
Stock-based compensation (Note 7)	**9,775**	6,339	2,733
Amortization of debt issuance costs (Note 6)	**2,415**	5,691	—
Cash settlement of restricted share units	**(564)**	(1,234)	(1,392)
Unrealized foreign exchange loss (gain)	**837**	(1,428)	(8,380)
Financial instruments loss (Note 12)	**15,929**	10,279	2,027
Cash settlement of financial instruments	**1,563**	438	(3,749)
Cash settlement of asset retirement obligation (Note 8)	**(1,336)**	(605)	(6,217)
Loss on sale of business units (Note 3 and 5) and (gain) on acquisition	**44,385**	(929)	—
Other gain	**—**	—	(502)
Net change in assets and liabilities from operating activities (Note 13)	**(29,217)**	(11,337)	(39,048)
Net cash provided by operating activities	**189,644**	93,042	62,305
Investing Activities			
Additions to property, plant and equipment (Note 3)	**(251,041)**	(127,789)	(156,639)
Property acquisitions (Note 5)	**(34,410)**	(19,388)	—
Net proceeds from sale of business units (Note 5)	**32,968**	—	—
Cash paid for investments (Note 5)	**(11,000)**	—	—
Cash paid for business combinations, net of cash acquired	**—**	(488,196)	—
Proceeds from the sale of oil and gas properties (Note 5)	**—**	6,000	—
Proceeds from sale of marketable securities (Note 12)	**—**	2,325	—
Changes in non-cash investing working capital	**19,680**	21,116	(76,844)
Net cash used in investing activities	**(243,803)**	(605,932)	(233,483)
Financing Activities			
Proceeds from bank debt, net of issuance costs	**167,043)**	256,065	—
Repayment of bank debt	**(110,000)**	(252,181)	—
Repurchase of shares of Common Stock (Note 7)	**(17,916)**	—	(9,999)
Proceeds from issuance of shares of Common Stock, net of issuance costs	**—**	128,273	722
Proceeds from issuance of subscription receipts, net of issuance costs	**—**	165,805	—
Proceeds from issuance of Convertible Notes, net of issuance costs	**—**	109,090	—
Net cash provided by (used in) financing activities	**39,127**	407,052	(9,277)
Foreign exchange (loss) gain on cash, cash equivalents and restricted cash and cash equivalents	**(1,557)**	354	(6,516)
Net decrease in cash, cash equivalents and restricted cash and cash equivalents	**(16,589)**	(105,484)	(186,971)
Cash, cash equivalents and restricted cash and cash equivalents, beginning of year (Note 13)	**43,267**	148,751	335,722
Cash, cash equivalents and restricted cash and cash equivalents, end of year (Note 13)	**$ 26,678**	$ 43,267	$ 148,751

Supplemental cash flow disclosures (Note 13)

(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,		
	2017	**2016**	**2015**
Share Capital			
Balance, beginning of year	**$ 10,303**	$ 10,186	$ 10,190
Issuance of Common Stock (Note 7)	**—**	117	—
Repurchase of Common Stock (Note 7)	**(8)**	—	(4)
Balance, end of year	**10,295**	10,303	10,186
Additional Paid in Capital			
Balance, beginning of year	**1,342,656**	1,019,863	1,026,873
Issuance of Common Stock, net of share issuance costs (Note 7)	**—**	314,425	—
Exercise of stock options (Note 7)	**—**	5,347	722
Stock-based compensation (Note 7)	**2,496**	3,021	2,263
Repurchase of Common Stock (Note 7)	**(17,908)**	—	(9,995
Balance, end of year	**1,327,244**	1,342,656	1,019,863
(Deficit) Retained Earnings			
Balance, beginning of year	**(493,972)**	(28,407)	239,622
Net loss	**(31,708)**	(465,565)	(268,029)
Cumulative adjustment for accounting changes related to tax reorganizations (Note 2)	**124,476**	—	—
Balance, end of year	**(401,204)**	(493,972)	(28,407)
Total Shareholders' Equity	**$ 936,335**	$ 858,987	$ 1,001,642

(See notes to the consolidated financial statements)

(Expressed in U.S. Dollars, unless otherwise indicated)

1. Description of Business

Gran Tierra Energy Inc., a Delaware corporation (the "**Company**" or "**Gran Tierra**"), is a publicly traded company focused on oil and natural gas exploration and production in Colombia. The Company also had business activities in Brazil until June 30, 2017, and in Peru until December 18, 2017.

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. Significant estimates made by management include: oil and natural gas reserves and related present value of future cash flows; depreciation, depletion, amortization and impairment ("**DD&A**"); impairment assessments of goodwill; timing of transfers from oil and gas properties not subject to 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 and investment. 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 comprises cash and cash equivalents pledged to secure letters of credit and to settle asset retirement obligations. Letters of credit currently secured by cash relate to work commitment guarantees contained in exploration contracts. 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

The Company estimates losses on receivables based on known uncollectible accounts, if any, and historical experience of losses incurred and accrues a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated. The allowance for doubtful receivables was nil at December 31, 2017 and 2016.

Equity method investment

During December 2017, the Company acquired an investment in common shares of Sterling in connection with the sale of its Peru business unit (Note 5). At December 31, 2017, this investment represented approximately 46% of Sterling's issued and outstanding common shares. The Company determined that it did not have a controlling financial interest in Sterling, but could exert significant influence over Sterling's operating and financial policies as a result of its ownership interest in Sterling and the right to nominate two directors to Sterling's board of directors. Accordingly, Gran Tierra accounted for its investment in the common shares of Sterling as an equity method investment, but elected the fair value option for this investment to reflect the value that market participants would use to value the investment. The fair value of the investment in Sterling's common shares is recorded in 'Investments' in the consolidated balance sheet, and the change in fair value is recorded in the consolidated statement of operations as financial instruments gains or losses.

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 cash royalties.

Income taxes

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

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

Oil and gas properties

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

The Company computes depletion of oil and natural gas properties on a quarterly basis using the unit-of-production method based upon production and estimates of proved reserve quantities. Future development costs related to properties with proved reserves are also included in the amortization base for computation of depletion. The costs of unproved properties are excluded from the amortization 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 results in a lower DD&A rate in future periods. A write-down may not be reversed in future periods even though higher oil and natural gas prices may subsequently increase the ceiling.

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

Unproved properties are not depleted pending the determination of the existence of proved reserves. Costs are transferred into the depletable base on an ongoing basis as the properties are evaluated and proved reserves are established or impairment is determined. Unproved properties are evaluated quarterly to ascertain whether impairment has occurred. This evaluation considers, among other factors, seismic data, requirements to relinquish acreage, drilling results and activity, remaining time in the commitment period, remaining capital plans, and political, economic, and market conditions. During any period in which factors indicate an impairment, the cumulative costs incurred to date for such property are transferred to the full cost pool and are then subject to 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 are 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 and automobiles. Depreciation is provided using the declining-balance method at a 30% annual rate for furniture and fixtures, computer equipment and automobiles. Leasehold improvements are depreciated on a straight-line basis over the shorter of the estimated useful life and the term of the related lease. The cost of repairs and maintenance is charged to expense as incurred.

Goodwill

Goodwill represents the excess of the aggregate of the consideration transferred over the net identifiable assets acquired and liabilities assumed. The Company assesses qualitative factors annually, or more frequently if necessary, to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount and whether it is necessary to perform the goodwill impairment test. The impairment test requires allocating goodwill and certain other assets and liabilities to assigned reporting units. The fair value of each reporting unit is estimated and compared with its net book value. An impairment loss is recognized if the estimated fair value of the reporting unit is less than its carrying amount, not exceeding the carrying amount of goodwill allocated to that reporting unit. Because quoted market prices are not available for the Company's reporting unit, the fair value of the reporting unit is estimated based upon estimated future cash flows of the reporting unit. The goodwill relates entirely to the Colombia reportable segment. The Company performed a qualitative assessment of goodwill at December 31, 2017, and based on this assessment, no impairment of goodwill was identified.

Convertible Notes

The Company accounts for its 5.00% Convertible Senior Notes due 2021 (the "**Convertible Notes**") as a liability in their entirety. The embedded features of the Convertible Notes were assessed for bifurcation from the Convertible Notes under the applicable provisions, including the basic conversion feature, the fundamental change make-whole provision and the put and call options. Based on an assessment, the Company concluded that these embedded features did not meet the criteria to be accounted for separately.

The Company incurred debt issuance costs in connection with the issuance of the Convertible Notes which have been presented as a direct deduction against the carrying amount of the Convertible Notes and are being amortized to interest expense using the effective interest method over the contractual term of the Convertible Notes.

Revenue recognition

Revenue from the production of oil and natural gas is recognized when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable, the sale is evidenced by a contract and collection of the revenue is reasonably assured.

Revenue represents the Company's share and is recorded net of royalty payments to governments and other mineral interest owners.

Stock-based compensation

The Company 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.

Loss per share

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

Recently Adopted Accounting Pronouncements

Simplifying the Measurement of Inventory

In July 2015, the Financial Accounting Standards Board ("**FASB**") issued ASU 2015-11, "Simplifying the Measurement of Inventory". The ASU provides guidance for the subsequent measurement of inventory and requires that inventory that is measured using average cost be measured at the lower of cost and net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The ASU was effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. The implementation of this update did not have an impact on the Company's consolidated financial position, results of operations or cash flows or disclosure.

Employee Share-Based Payment Accounting

In March 2016, the FASB issued ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting". This ASU simplifies several aspects of the accounting for employee share-based payment transactions, including the accounting for forfeitures, income taxes, and statutory tax withholding requirements. The ASU was effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. The Company elected to continue to estimate the total number of awards for which the requisite service period will not be rendered. The implementation of this update did not impact the Company's consolidated financial position, results of operations or cash flows or disclosure.

Income Taxes **-** *Intra-Entity Transfers of Assets Other than Inventory*

At December 31, 2016, GAAP prohibited the recognition of current and deferred income taxes for intra-entity transfers until an asset leaves the consolidated group, therefore, the current income tax effect of tax reorganizations completed in 2016 was deferred and recognized as prepaid income taxes. At December 31, 2016, the Company's balance sheet included $54.1 million of prepaid income taxes,

$12.3 million in current prepaid taxes and $41.8 million in long-term prepaid taxes, and $37.5 million of current income taxes payable relating to tax reorganizations completed in 2016.

In October 2016, the FASB issued ASU 2016-16, "Intra-Entity Transfers of Assets Other than Inventory." This ASU requires companies to recognize the income tax effects of intercompany sales or transfers of assets, other than inventory, in the income statement as income tax expense or benefit in the period the sale or transfer occurs. This ASU is effective for fiscal years beginning after December 15, 2017, and interim periods within those years. Early adoption was permitted as of the beginning of an annual reporting period. The ASU is required to be applied on a modified retrospective basis with a cumulative-effect adjustment directly to retained earnings in the period of adoption. The Company early adopted this ASU on January 1, 2017, and in the three months ending March 31, 2017, wrote off the income tax effects that had been deferred from past intercompany transactions to opening deficit. A total of $124.5 million, representing deferred tax assets of $178.6 million, net of $54.1 million of prepaid tax, was recorded directly to opening deficit at January 1, 2017. Deferred tax assets recorded upon adoption were assessed for realizability under Accounting Standards Codification ("**ASC**") 740 "Income Taxes", and, valuation allowances were recognized on those deferred tax assets as necessary on the date of adoption. The adoption of ASU 2016-16 did not have any effect on the Company's cash flows.

Restricted Cash and Cash Equivalents

In November 2016, the FASB issued ASU 2016-18, "Restricted Cash". ASU 2016-18 requires that a statement of cash flows explain the change during the period in the total cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents. ASU 2016-18 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2017. Early adoption was permitted. The Company early adopted this ASU on January 1, 2017, on a retrospective basis to each period presented. The implementation of this ASU did not impact the Company's consolidated financial position or results of operations. For the year ended December 31, 2016, the net decrease in cash, cash equivalents and restricted cash and cash equivalents currently disclosed was $105.5 million, compared with the net decrease in cash and cash equivalents of $120.2 million as previously disclosed in the consolidated statement of cash flows prior to the adoption of ASU 2016-18. For the year ended December 31, 2015, the net decrease in cash, cash equivalents and restricted cash and cash equivalents currently disclosed was $187.0 million, compared with the net decrease in cash and cash equivalents of $186.5 million as previously disclosed in the consolidated statement of cash flows prior to the adoption of ASU 2016-18.

Clarifying the Definition of a Business

In January 2017, the FASB issued ASU 2017-01, "Clarifying the Definition of a Business". ASU 2017-01 narrows the definition of a business and provides a framework that gives entities a basis for making reasonable judgments about whether a transaction involves an asset or a business. ASU 2017-01 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2017. Early adoption was permitted and the Company adopted this ASU on January 1, 2017. The Company now applies an initial screen for determining whether a transaction involves an asset or a business. When substantially all of the fair value of the gross assets acquired is concentrated in a single identified asset, or group of similar identifiable assets, the set will not be a business and no goodwill or gain on acquisition will be recognized. If the screen is not met, a set cannot be considered a business unless it includes an input and a substantive process that together significantly contribute to the ability to create an output. The Company's acquisition of the Santana and Nancy Burdine-Maxine oil and gas properties during the year ended December 31, 2017 was not considered a business under this ASU and therefore not allocated goodwill or gain on acquisition (Note 5).

Simplifying the Test for Goodwill Impairment

In January 2017, the FASB issued ASU 2017-04, "Simplifying the Test for Goodwill Impairment". ASU 2017-04 eliminates step 2 of the goodwill impairment test. An entity no longer will determine goodwill impairment by calculating the implied fair value of goodwill by assigning the fair value of a reporting unit to all of its assets and liabilities as if that reporting unit had been acquired in a business combination. Goodwill impairment will now be the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill. ASU 2017-04 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2019. Early adoption is permitted. At December 31, 2017, the Company performed a qualitative assessment of goodwill and, based on this assessment, no impairment of goodwill was identified.

Recently Issued Accounting Pronouncements

Revenue from Contracts with Customers

In May 2014, the FASB issued guidance regarding the accounting for revenue from contracts with customers. In August 2015, the FASB issued ASU 2015-14, "Revenue from Contracts with Customers - Deferral of the Effective Date". The ASU deferred the effective date of the new revenue recognition model by one year. As a result, the guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. In March 2016, the FASB issued ASU 2016-08, "Principal versus Agent Considerations (Reporting Revenue Gross versus Net)" which clarifies implementation guidance on principal versus agent considerations. In April, May and December 2016, the FASB issued ASU 2016-10, "Identifying Performance Obligations and Licensing", ASU 2016-12, "Narrow-Scope Improvements and Practical Expedients" and ASU 2016-20 "Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers", respectively, which addressed implementation issues and provided technical corrections. The guidance may be applied retrospectively or using a modified retrospective approach to adjust retained earnings.

The Company has completed its evaluation of the impact of the ASU and has reviewed its various revenue streams and underlying contracts. The Company adopted the new standard using the modified retrospective method at the date of adoption, January 1, 2018. Adoption of the ASU did not have a material impact on the Company's consolidated financial statements, other than enhanced disclosure related to revenues from contracts with customers as prescribed by ASU.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU 2016-01, "Recognition and Measurement of Financial Assets and Financial Liabilities". ASU 2016-01 addresses certain aspects of recognition, measurement, presentation and disclosure of financial instruments. ASU 2016-01 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2017. This ASU is not expected to have a material impact on the Company's consolidated financial position, results of operations or cash flows or disclosure.

Leases

In February 2016, the FASB issued ASU 2016-02, "Leases". This ASU will require most lease assets and lease liabilities to be recognized on the balance sheet and the disclosure of key information about lease arrangements. The ASU will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2018. The Company is currently assessing the impact the new lease standard will have on its consolidated financial position, results of operations, cash flows, and disclosure.

Financial Instruments - Credit Losses

In June 2016, the FASB issued ASU 2016-13, "Financial Instruments - Credit Losses". This ASU replaces the current incurred loss impairment methodology with a methodology that reflects expected credit losses and requires a broader range of reasonable and supportable information to support credit loss estimates. The ASU will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2019. The Company is currently assessing the impact this update will have on its consolidated financial position, results of operations, cash flows, and disclosure.

3. Segment and Geographic Reporting

The Company is primarily engaged in the exploration and production of oil and natural gas. The Company has one reportable segment based on geographic organization, Colombia. Prior to the sale of the Company's Brazil business unit effective June 30, 2017 and its Peru business unit effective December 18, 2017, Brazil and Peru were reportable segments. The "All Other" category represents the

Company's corporate, Brazil and Peru activities until the date of sale. The Company evaluates reportable segment performance based on income or loss before income taxes.

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

	Year Ended December 31, 2017		
(Thousands of U.S. Dollars)	**Colombia**	**All Other**	**Total**
Oil and natural gas sales	**$ 413,316**	**$ 8,418**	**$ 421,734**
DD&A expenses	**126,453**	**4,882**	**131,335**
Asset impairment	**—**	**1,514**	**1,514**
General and administrative expenses	**23,500**	**15,514**	**39,014**
Interest expense	**486**	**13,396**	**13,882**
Loss on sale	**—**	**(44,385)**	**(44,385)**
Income (loss) before income taxes	**111,829**	**(74,499)**	**37,330**
Segment capital expenditures	**242,636**	**8,405**	**251,041**

	Year Ended December 31, 2016		
(Thousands of U.S. Dollars)	**Colombia**	**All Other**	**Total**
Oil and natural gas sales	$ 280,872	$ 8,397	$ 289,269
DD&A expenses	132,569	6,966	139,535
Asset impairment	514,314	102,335	616,649
General and administrative expenses	17,187	16,031	33,218
Interest expense	—	14,145	14,145
Gain on acquisition	—	929	929
Loss before income taxes	(505,447)	(144,787)	(650,234)
Segment capital expenditures	105,963	21,826	127,789

	Year Ended December 31, 2015		
(Thousands of U.S. Dollars)	**Colombia**	**All Other**	**Total**
Oil and natural gas sales	$ 269,035	$ 6,976	$ 276,011
DD&A expenses	167,701	8,685	176,386
Asset impairment	235,069	88,849	323,918
General and administrative expenses	9,805	22,548	32,353
Loss before income taxes	(238,463)	(129,625)	(368,088)
Segment capital expenditures	85,326	71,313	156,639

	As at December 31, 2017		
(Thousands of U.S. Dollars)	**Colombia**	**All Other**	**Total**
Property, plant and equipment	**$ 1,096,833**	**$ 2,391**	**$ 1,099,224**
Goodwill	**102,581**	**—**	**$ 102,581**
All other assets	**176,980**	**50,834**	**$ 227,814**
Total Assets	**$ 1,376,394**	**$ 53,225**	**$ 1,429,619**

	As at December 31, 2016		
(Thousands of U.S. Dollars)	**Colombia**	**All Other**	**Total**
Property, plant and equipment	$ 939,947	$ 126,662	$ 1,066,609
Goodwill	102,581	—	$ 102,581
All other assets	177,393	21,313	$ 198,706
Total Assets	$ 1,219,921	$ 147,975	$ 1,367,896

The following table presents the number of customers from whom the Company derived 10% or more of its consolidated oil and gas sales and sales as a percentage of the Company's consolidated oil and gas sales to each customer. All of these customers were in the Company's Colombian reportable segment:

	Year Ended December 31, 2017									
		2017			**2016**			**2015**		
Number of significant customers		**3**			3			4		
Sales to each significant customer as % of oil and gas sales	**44%**	**31%**	**17%**	40%	34%	13%	43%	15%	13%	12%

4. Accounts Receivable

	As at December 31,	
(Thousands of U.S. Dollars)	**2017**	**2016**
Trade	**$ 37,794**	$ 39,203
Other	**7,559**	6,495
	$ 45,353	$ 45,698

5. Property, Plant and Equipment

	As at December 31,	
(Thousands of U.S. Dollars)	**2017**	2016
Oil and natural gas properties		
Proved	**$ 2,810,796**	$ 2,652,171
Unproved	**464,948**	647,774
	3,275,744	3,299,945
Other	**26,401**	29,445
	3,302,145	3,329,390
Accumulated depletion, depreciation and impairment	**(2,202,921)**	(2,262,781)
	$ 1,099,224	$ 1,066,609

Depletion and depreciation expense on property, plant and equipment for the year ended December 31, 2017, was $126.8 million (year ended December 31, 2016 - $130.2 million; year ended December 31, 2015 - $177.9 million). A portion of depletion and depreciation expense was recorded as inventory in each year and adjusted for inventory changes.

Asset impairment for the three years ended December 31, 2017, was as follows:

	Year Ended December 31, 2017		
(Thousands of U.S. Dollars)	**2017**	**2016**	**2015**
Impairment of oil and natural gas properties	**$ 1,514**	$ 615,985	$ 321,285
Impairment of inventory	**—**	664	2,633
	$ 1,514	$ 616,649	$ 323,918

In the year ended December 31, 2016, the Company recorded ceiling test impairment losses of $513.7 million in its Colombia cost center, and $71.1 million in its Brazil cost center. The Colombia ceiling test impairment loss related to lower oil prices and the fact that the acquisitions of PetroLatina and PetroAmerica were initially added into the cost base at estimated fair value. However, these acquired assets were subjected to a prescribed U.S. GAAP ceiling test, which is not a fair value test, and which, as noted below, uses constant commodity pricing that averages prices during the preceding 12 months. The Brazil ceiling test impairment loss related to continued low oil prices and increased costs in the depletable base as a result of a $45.0 million impairment of unproved properties.

In the year ended December 31, 2015, the Company recorded ceiling test impairment losses of $232.4 million in its Colombia cost center, and $46.9 million in its Brazil cost center as a result of lower realized prices.

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 during the 12 months period prior to the ending date of the period covered by the balance sheet, calculated as an unweighted arithmetic average of the first-day-of-the month price for each month within such period for that oil and natural gas. That average price is then held constant, except for changes which are fixed and determinable by existing contracts. 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 the Company's reserves. In accordance with GAAP, Gran Tierra used an average Brent price of $54.19 per bbl for the purposes of the December 31, 2017 ceiling test calculations (September 30, 2017 - 52.70, June 30, 2017 - $51.35, March 31, 2017 - $49.33; December 31, 2016 - $42.92; September 30, 2016 - $42.23; June 30, 2016 - $44.48, March 31, 2016 - $48.79; December 31, 2015 - $54.08).

In the years ended December 31, 2016 and 2015, the Company recorded impairment losses of $31.2 million and $41.9 million, respectively, related to costs incurred on Block 95 and other blocks in Peru. On February 19, 2015, the Company made the decision to cease all further development expenditures on the Bretaña Field on Block 95 other than what is necessary to maintain tangible asset integrity and security.

Acquisition of Santana and Nancy Burdine-Maxine Blocks

On April 27, 2017, the Company acquired the Santana and Nancy-Burdine-Maxine Blocks in the Putumayo Basin for cash consideration of $30.4 million. The acquisition was accounted for as an asset acquisition with the consideration paid allocated on a relative fair value basis to the net assets acquired.

The following table shows the allocation of the cost of the acquisition based on the relative fair values of the assets and liabilities acquired:

(Thousands of U.S. Dollars)		
Cost of asset acquisition:		
Cash	$	30,410
Allocation of Consideration Paid:		
Oil and gas properties		
Proved	$	24,405
Unproved		8,649
		33,054
Inventory		869
Asset retirement obligation - long-term		(3,513)
	$	30,410

Acquisition of PGC

On January 25, 2016, the Company acquired all of the issued and outstanding common shares of PGC, pursuant to the terms and conditions of an acquisition agreement dated January 14, 2016. Upon completion of the transaction, PGC became an indirect wholly-owned subsidiary of Gran Tierra. The net purchase price of PGC was $19.4 million, after giving consideration to net working capital of $18.3 million. The acquisition was accounted for as an asset acquisition with the excess consideration paid over the fair value of the net assets acquired allocated on a relative fair value basis to the net assets acquired.

(Thousands of U.S. Dollars)		
Cost of asset acquisition:		
Cash	$	37,727
Allocation of Consideration Paid:		
Oil and gas properties		
Proved	$	12,228
Unproved		15,563
		27,791
Net working capital (including cash acquired of $0.2 million and restricted cash of $18.6 million)		18,339
Asset retirement obligation - long-term		(8,403)
	$	37,727

Property acquisitions in the year ended December 31, 2017 included $4.0 million of contingent consideration related to the 2016 acquisition of PGC. The contingent consideration was subject to Gran Tierra reaching a certain level of production plus gross proved plus probable reserves in the Putumayo-

7 Block and was payable at December 31, 2017. The Company recognized contingent consideration in accounts payable and accrued liabilities on its balance sheet as at December 31, 2017.

Disposition of Peru Business Unit

On December 18, 2017, Gran Tierra completed the sale of its Peru business unit. Pursuant to the divestiture, Sterling acquired all of the issued and outstanding shares in Gran Tierra's indirect, wholly owned subsidiary that indirectly held all of its Peruvian assets for aggregate consideration of $33.5 million, comprised of approximately 187.3 million common shares of Sterling and an estimated cash-settled working capital adjustment of $0.4 million. Escrow conditions are applicable to 90% of the share consideration, which will be released from escrow at 15% every 6 months for 36 months following December 18, 2017. Additionally, in connection with the divestiture, Gran Tierra purchased $11.0 million of subscription receipts which were exchangeable for common shares of PetroTal Ltd. and subsequently exchanged them for approximately 58.9 million common shares of Sterling. After giving effect to the divestiture, Gran Tierra directly and indirectly holds approximately 246.2 million common shares representing approximately 46% of Sterling's issued and outstanding common shares. Sterling is a junior oil and gas company focused on development of oil and gas assets in Peru.

In connection with the divestiture, Gran Tierra, through two of its indirect, wholly owned subsidiaries, entered into an investor rights agreement with Sterling, pursuant to which, Gran Tierra has the right to nominate two directors to the board of Sterling, as well as certain demand and piggy-back registration rights and certain pre-emptive rights, subject to the terms and conditions set forth in the investor rights agreement. Gran Tierra is prohibited from exercising voting rights over more than 30% of the issued and outstanding Sterling Common Shares. In addition, Gran Tierra, through its indirect, wholly-owned subsidiary, entered into a carried interest and option agreement with Sterling and a Peruvian subsidiary, pursuant to which Gran Tierra has a 20% carried working interest in Block 107, located in the Ucayali basin in Peru, which interest may, at the option of Gran Tierra, either be converted to a non-carried working interest or be forfeited following the drilling of an exploration well in Block 107.

At December 18, 2017, the net book value of the Peru business unit was greater than proceeds received resulting in a $34.1 million loss on sale.

At December 31, 2016, assets and liabilities of the Peru business unit were as follows:

(Thousands of U.S. Dollars)	**As at December 31, 2016**	
Current assets	$	1,051
Property, plant and equipment		68,428
Other long-term assets		9,799
	$	79,278
Current liabilities	$	(940)
Long-term liabilities		(13,370)
	$	(14,310)

Disposition of Brazil Business Unit

On June 30, 2017, the Company, through two of its indirect subsidiaries (the "**Selling Subsidiaries**"), completed the previously announced disposition of its assets in Brazil. Gran Tierra completed the disposition of its Brazil business unit for a purchase price of $35.0 million, which, after certain final closing adjustments, resulted in cash consideration paid to the Selling Subsidiaries of approximately $36.8 million.

At June 30, 2017, the net book value of the Brazil business unit was greater than proceeds received resulting in a $10.2 million loss on sale.

At December 31, 2016, assets and liabilities of the Brazil business unit were as follows:

(Thousands of U.S. Dollars)	As at December 31, 2016	
Current assets	$	1,634
Property, plant and equipment		55,376
	$	57,010
Current liabilities	$	(11,590)
Long-term liabilities		(2,297)
	$	(13,887)

Other

During the year ended December 31, 2016, Gran Tierra sold non-operated and non-core assets in Colombia to a third party for cash consideration of $6.0 million.

Unproved oil and natural gas properties

At December 31, 2017, unproved oil and natural gas properties consist of exploration lands held in Colombia. 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 76% of costs not subject to depletion at December 31, 2017, will be transferred to the depletable base within the next five years and the remainder in the next five to 10 years.

The following is a summary of Gran Tierra's oil and natural gas properties not subject to depletion as at December 31, 2017:

	Costs Incurred in									
(Thousands of U.S. Dollars)	2017		2016		2015		Prior to 2015		Total	
Acquisition costs – Colombia	**$**	**8,076**	$	319,025	$	—	$	33,080	$	360,181
Exploration costs – Colombia		**52,769**		10,124		8,795		33,079		104,767
	$	**60,845**	$	329,149	$	8,795	$	66,159	$	464,948

6. Debt and Debt Issuance Costs

The Company's debt at December 31, 2017 and 2016, was as follows:

	As at December 31,			
(Thousands of U.S. Dollars)	2017		2016	
Convertible Notes (a)	**$**	**115,000**	$	115,000
Revolving credit facility (b)		**148,000**		90,000
Unamortized debt issuance costs		**(6,458)**		(7,917)
Long-term debt	**$**	**256,542**	$	197,083

(a) *Convertible Notes*

At December 31, 2017, the Company had $115 million of Convertible Notes outstanding. The Convertible Notes bear interest at a rate of 5.00% per year, payable semi-annually in arrears on April 1 and October 1 of each year, beginning on October 1, 2016. The Convertible Notes will mature on April 1, 2021, unless earlier redeemed, repurchased or converted. The Convertible Notes are unsecured and are subordinated to secured debt to the extent of the value of the assets securing such indebtedness.

The Convertible Notes are convertible at the option of the holder at any time prior to the close of business on the business day immediately preceding the maturity date. The conversion rate is initially 311.4295 shares of Common Stock per $1,000 principal amount of Convertible Notes (equivalent to an initial conversion price of approximately $3.21 per share of Common Stock). The conversion rate is subject to adjustment in some events but will not be adjusted for any accrued and unpaid interest. In addition, following certain corporate events that occur prior to the maturity date, the Company will increase the conversion rate for a holder who elects to convert its Convertible Notes in connection with such a corporate event in certain circumstances.

The Company may not redeem the Convertible Notes prior to April 5, 2019, except in certain circumstances following a fundamental change (as defined in the indenture governing the Convertible Notes). The Company may redeem for all cash or any portion of the Convertible Notes, at its option, on or after April 5, 2019, if (terms below are as defined in the indenture governing the Convertible Notes):

(i) the last reported sale price of the Company's Common Stock has been at least 150% of the conversion price then in effect for at least 20 trading days (whether or not consecutive) during any 30 consecutive trading day period (including the last trading day of such period) ending on, and including, the trading day immediately preceding the date on which the Company provides notice of redemption; and

(ii) the Company has filed all reports that it is required to file with the SEC pursuant to Section 13 or 15(d) of the Exchange Act, as applicable (other than current reports on Form 8-K), during the twelve months preceding the date on which the Company provides such notice.

The redemption price will be equal to 100% of the principal amount of the Convertible Notes to be redeemed, plus accrued and unpaid interest, if any, to, but excluding, the redemption date. No sinking fund is provided for the Convertible Notes.

If the Company undergoes a fundamental change, holders may require the Company to repurchase for cash all or any portion of their Convertible Notes at a fundamental change repurchase price equal to 100% of the principal amount of the Convertible Notes to be repurchased, plus accrued and unpaid interest to, but excluding, the fundamental change repurchase date.

Net proceeds from the sale of the Convertible Notes were $109.1 million, after deducting the initial purchasers' discount and the offering expenses payable by the Company.

(b) ***Credit Facility***

At December 31, 2017, the Company had a revolving credit facility with a syndicate of lenders with a borrowing base of $300 million. Availability under the revolving credit facility is determined by the reserves-based borrowing base determined by the lenders. On November 10, 2017, as a result of the Ninth Amendment to the credit agreement, the borrowing base of $300 million was reaffirmed and, among other things, the maturity date of the borrowing under the revolving credit facility was extended from October 1, 2018 to November 10, 2020. The next re-determination of the borrowing base is due to occur no later than May 2018.

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 2.15% to 3.65% (December 31, 2016 - 2.00% to 3.00%), or an alternate base rate plus a margin ranging from 1.15% to 2.65%, in each case based on the borrowing base utilization percentage. The alternate base rate is currently the U.S. prime rate. At December 31, 2017 the weighted-average interest rate on the balance outstanding on the Company's revolving credit facility was approximately 3.64%. Undrawn amounts under the revolving credit facility bear interest from 0.54% to 0.91% (December 31, 2016 - 0.75%) per annum, based on the average daily amount of unused commitments. A letter of credit participation fee of 0.25% per annum will accrue on the average daily amount of letter of credit exposure.

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 on 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.

(c) ***Interest expense***

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

(Thousands of U.S. Dollars)	Year Ended December 31, 2017	2016	2015
Contractual interest and other financing expenses	**$ 11,467**	$ 8,454	$ —
Amortization of debt issuance costs	**2,415**	5,691	—
	$ 13,882	$ 14,145	$ —

The Company incurred debt issuance costs in connection with the issuance of the Convertible Notes and its revolving credit facility. As at December 31, 2017, 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.

7. Share Capital

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

As at December 31, 2017, outstanding share capital consists of 385,191,042 shares of Common Stock of the Company, 4,422,776 exchangeable shares of Gran Tierra Exchangeco Inc., (the "**Exchangeco exchangeable shares**") and 1,688,889 exchangeable shares of Gran Tierra Goldstrike Inc. (the "**Goldstrike exchangeable shares**"). The Exchangeco exchangeable shares were issued upon the acquisition of Solana. The Goldstrike exchangeable shares were issued upon the business combination between Gran Tierra Energy Inc., an Alberta corporation, and Goldstrike, Inc., which is now the Company. The redemption date for the Exchangeco exchangeable shares and the Goldstrike exchangeable shares is a date to be established by the applicable Board of Directors.

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

	Shares of Common Stock	Exchangeable Shares of Gran Tierra Exchangeco Inc.	Exchangeable Shares of Gran Tierra Goldstrike Inc.
Balance, December 31, 2016	390,807,194	4,812,592	3,387,302
Exchange of exchangeable shares	2,088,229	(389,816)	(1,698,413)
Shares repurchased and canceled	(7,704,381)	—	—
Balance, December 31, 2017	385,191,042	4,422,776	1,688,889

Share Repurchase Program

On February 6, 2017, the Company announced that it had implemented a share repurchase program (the "**2017 Program**") through the facilities of the Toronto Stock Exchange ("**TSX**"), the NYSE American and eligible alternative trading platforms in Canada and the United States. Under the 2017 Program, the Company is able to purchase at prevailing market prices up to 19,540,359 shares of Common Stock, representing 5.0% of the issued and outstanding shares of Common Stock as of January 27, 2017. Shares purchased pursuant to the 2017 Program will be canceled. The 2017 Program expired on February 7, 2018.

Equity Compensation Awards

The Company has an equity compensation program in place for its executives and employees. Equity compensation grants vest either based solely on recipient's continued employment or achievement of certain key measures of performance. Equity awards consist 80% of Performance Stock Units ("**PSUs**") and 20% of stock options. The Company's equity compensation awards outstanding as at December 31, 2017, include PSUs, deferred share units ("**DSUs**"), restricted stock units ("**RSUs**") and stock options.

In accordance with the 2007 Equity Incentive Plan, 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.

The following table provides information about PSU, DSU, RSU and stock option activity for the year ended December 31, 2017:

	PSUs	DSUs	RSUs	Stock Options	
	Number of Outstanding Share Units	**Number of Outstanding Share Units**	**Number of Outstanding Share Units**	**Number of Outstanding Stock Options**	**Weighted Average Exercise Price /Stock Option ($)**
Balance, December 31, 2016	3,362,717	208,698	359,145	9,239,478	$ 4.16
Granted	3,422,170	247,070	—	2,029,035	2.54
Exercised	—	—	(224,548)	—	—
Forfeited	(652,936)	—	(12,507)	(911,154)	(4.79)
Expired	—	—	—	(1,396,667)	(4.65)
Balance, December 31, 2017	6,131,951	455,768	122,090	8,960,692	$ 3.65
Exercisable, at December 31, 2017				5,044,267	$ 4.33
Vested, or expected to vest, at December 31, 2017, through the life of the options				8,792,816	$ 3.67

Stock-based compensation expense for the year ended December 31, 2017, was $9.8 million (December 31, 2016 - $6.3 million; December 31, 2015 - $2.7 million) and was primarily recorded in G&A expenses.

At December 31, 2017, there was $13.7 million (December 31, 2016 - $10.0 million) of unrecognized compensation cost related to unvested PSUs, RSUs and stock options which is expected 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, 2017 was 2.9 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 continued employment of the grantee. The number of PSUs that vest may range from zero to 200% of the target number granted based on the Company's performance with respect to the applicable performance targets. The performance targets for the PSUs outstanding as at December 31, 2017, 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) 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; and

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

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. PSUs in excess of the target number granted will vest and be settled if performance exceeds the targeted performance goals. The Company currently intends to settle the PSUs in cash.

DSUs and RSUs

DSUs and RSUs 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. The Company's historic practice has been to settle RSUs in cash and the Company currently intends to settle the RSUs and DSUs outstanding as at December 31, 2017 in cash, and, therefore, DSUs and RSUs are accounted for as liability instruments. Once a DSU or RSU is vested, it is immediately settled. During the year ended December 31, 2017, DSUs were granted to directors and will vest 100% at such time the grantee ceases to be a member of the Board of Directors. For the year ended December 31, 2017, the Company paid $0.6 million to cash settle RSUs (2016 - $1.2 million and 2015 - $1.4 million).

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. Stock options generally vest over three years. The term of stock options granted starting in May of 2013 is five years or three months after the grantee's end of service to the Company, whichever occurs first. Stock options granted prior to May of 2013 continue to have a term of ten years or three months after the end of the grantee's service to the Company, whichever occurs first.

For the year ended December 31, 2017, no stock options were exercised and no cash proceeds were received (2016 – 2,165,370 options exercised and shares issued; 2015 – 390,000 options exercised and shares issued).

At December 31, 2017, the weighted average remaining contractual term of outstanding stock options was 2.9 years and of exercisable stock options was 2.5 years.

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,		
	2017	**2016**	**2015**
Dividend yield (per share)	**Nil**	Nil	Nil
Volatility	**51% to 53%**	50% to 54%	46% to 50%
Weighted average volatility	**52%**	52%	48%
Risk-free interest rate	**1.75% to 2.10%**	0.94% to 1.78%	1.20% to 1.68%
Expected term	**4-5 years**	4-5 years	4-5 years

The weighted average grant date fair value for options granted in the year ended December 31, 2017, was $1.11 (2016 - $1.14; 2015 - $1.24). The weighted average grant date fair value for options vested in the year ended December 31, 2017, was $1.31 (2016 - $1.52; 2015 - $2.38). The total fair value of stock options vested during year ended December 31, 2017, was $2.5 million (2016 - $2.8 million; 2015 - $6.8 million).

Weighted Average Shares Outstanding

For the year ended December 31, 2017, 9,681,304 options, on a weighted average basis, (2016 - 10,662,034 options; 2015 - 13,432,287 options) were excluded from the diluted loss per share calculation as the options were anti-dilutive.

8. Asset Retirement Obligation

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

	Year Ended December 31,	
(Thousands of U.S. Dollars)	**2017**	**2016**
Balance, beginning of year	**$ 43,357**	$ 33,224
Liability incurred	**3,403**	2,606
Settlements	**(1,507)**	(872)
Accretion	**3,825**	2,789

Revisions in estimated liability		**(4,095)**		(6,856)
Liabilities associated with assets sold		**(16,932)**		(3,257)
Liabilities assumed in acquisitions		**3,513**		15,723
Balance, end of year	**$**	**31,564**	$	43,357
Asset retirement obligation - current	**$**	**323**	$	5,215
Asset retirement obligation - long-term		**31,241**		38,142
Balance, end of year	**$**	**31,564**	$	43,357

For the year ended December 31, 2017, settlements included cash payments of $1.3 million with the balance in accounts payable and accrued liabilities at December 31, 2017 (December 31, 2016 - $0.6 million). 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, 2017, the fair value of assets that were legally restricted for purposes of settling asset retirement obligations was $12.7 million (December 31, 2016 - $12.0 million). These assets were accounted for as restricted cash and cash equivalents on the Company's balance sheet.

9. **Taxes**

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

	Year Ended December 31,					
(Thousands of U.S. Dollars)		**2017**		**2016**		**2015**
Income (Loss) before income taxes						
United States	**$**	**(51,215)**	$	(23,986)	$	(14,061)
Foreign		**88,545**		(626,248)		(354,027)
		37,330		(650,234)		(368,088)
		35%		35%		35%
Income tax expense (recovery) expected		**13,066**		(227,582)		(128,831)
Impact of foreign taxes(1)		**12,310**		(9,799)		(13,087)
Other local taxes		**1,056**		1,998		2,354
Stock-based compensation		**2,001**		1,955		919
Increase in valuation allowance		**52,269**		47,675		37,691
Sale of Peru and Brazil business units		**(12,527)**		—		—
Non-deductible third party royalty in Colombia		**3,194**		2,550		3,416
Other permanent differences		**(2,331)**		(1,466)		(2,521)
Total income tax expense (recovery)	**$**	**69,038**	$	(184,669)	$	(100,059)
Current income tax expense						
United States	**$**	**3,457**	$	1,818	$	1,070
Foreign		**20,865**		18,304		14,313
		24,322		20,122		15,383
Deferred income tax expense (recovery)						
Foreign(2)		**44,716**		(204,791)		(115,442)
Total income tax expense (recovery)	**$**	**69,038**	$	(184,669)	$	(100,059)

(1) Impact of foreign taxes in the rate reconciliation are tax effected at the 35% statutory rate and were primarily due to higher income tax rates in Colombia. Impact of foreign taxes for the years ended December 31, 2017, 2016 and 2015, included $8.0 million (expense), $23.3 million (recovery) and $11.8 million (recovery), respectively, in Colombia.

(2) The deferred tax recovery for the year ended December 31, 2016, included $201.3 million associated with the ceiling test impairment loss in Colombia.

Undistributed earnings of foreign subsidiaries as of December 31, 2017, were considered to be permanently reinvested. A determination of the amount of unrecognized deferred tax liability on these undistributed earnings is not practicable.

In the fourth quarter of 2016, the Colombian government approved tax legislation consolidating the corporate Income and CREE taxes into a single income tax at 40% for 2017 (including a surtax of 6%), 37% for 2018 (including a surtax of 4%) and 33% for 2019 and onwards. The tax rates applied to the calculation of deferred income taxes, before valuation allowances, have been adjusted to reflect these changes. In the same legislation, the Colombian government also instituted a 5% dividend tax on distributions of previously taxed earnings from 2017 and onwards. The Law also increased the corporate minimum presumptive income tax from 3% to 3.5%. The tax is imposed on a taxpayer's net equity at the prior year-end when the presumptive income exceeds actual taxable profits.

The US government enacted the Tax Cuts and Jobs Act of 2017 ("**TCJA**") on December 22, 2017. As of December 31, 2017, the Company is still evaluating the complete tax effects of the enactment of the TCJA. However, the Company has determined a reasonable estimate of the impact of the TCJA on its existing deferred tax balances and the one-time transition tax. Based on this estimate, the Company has determined that the there is no current tax expense impact to its financial statements as a result of the TCJA. The Company has also calculated an estimated deferred tax asset impact of $59 million, which is subject to a full valuation allowance because its recognition does not meet the "more-likely-than-not" threshold. Of the estimated amount, $1.1 million relates to the remeasurement of certain deferred tax assets and liabilities based on the rate at which they are expected to reverse in the future.

As noted above, the Company is still evaluating the complete tax effects of the enactment of the TCJA and there are a number of uncertainties and ambiguities as to the interpretation and application of many of the provisions in the TCJA. In the absence of guidance on these matters and until the 2017 tax returns are finalized, which the Company expects to occur in October 2018, the Company expects to use what it believes are reasonable interpretations and assumptions in applying the TCJA for purposes of determining its cash tax liabilities and results of operations, which may change as it receives additional clarification and implementation guidance. Despite the fact that the Company has not prepared its tax returns for 2017, and therefore cannot provide a final estimate of 2017 foreign earning and profits, but considering the consistency of the Company's 2017 foreign operations with prior years, the Company's overall analysis of the one-time transition tax has not identified, nor does it expect to identify, any overall material adverse effect on its tax liability and financial condition.

	As at December 31,	
(Thousands of U.S. Dollars)	**2017**	**2016**
Deferred Tax Assets		
Tax benefit of operating loss carryforwards	**$ 60,460**	$ 74,604
Tax basis in excess of book basis	**62,768**	187,651
Foreign tax credits and other accruals	**70,157**	48,341
Tax benefit of capital loss carryforwards	**52,575**	32,278
Deferred tax assets before valuation allowance	**245,960**	342,874
Valuation allowance	**(188,650)**	(341,263)
	57,310	1,611
Deferred Tax Liabilities	**28,417**	107,230
Net Deferred Tax Assets (Liabilities)[1]	**$ 28,893**	$ (105,619)

(1) Effective November 1, 2016, several of Gran Tierra's subsidiaries executed intercompany sale agreements whereby certain depreciable assets were transferred within the consolidated Gran Tierra group. The purpose of the transaction was to improve the efficiency of Gran Tierra's operating and tax structures. The restructuring resulted in a consolidation of certain assets into a single entity in Colombia, an increase in the depreciable tax basis of the assets transferred, and current income taxes payable as at December 31, 2016, as a result of the capital gains taxes incurred. GAAP prohibited the recognition of current and deferred income taxes for intra-entity transfers until an asset leaves the consolidated group, therefore, the current and deferred income tax effect of the restructuring was deferred and recognized as prepaid income taxes at December 31, 2016. At January 1, 2017, the impact of the November 1, 2016, intercompany asset transfers was recognized pursuant to adoption of ASU 2016-16 (Note 2), which resulted in a material increase in the tax basis of certain Colombian assets. Accordingly, for 2017, this resulted in the Company realizing a change in its net deferred balance from a deferred tax liability at December 31, 2016, to a deferred tax asset at December 31, 2017.

	As at December 31,	
(Thousands of U.S. Dollars)	**2017**	**2016**
Operating loss carryforwards	**$ 199,138**	$ 257,023
Capital loss carryforwards	**$ 288,322**	$ 239,095
Of the operating loss and capital loss carryforwards, losses generated by the foreign subsidiaries of the Company.	**$ 392,053**	$ 496,118

In certain jurisdictions, operating loss carryforwards expire between 2018 and 2037, while certain other jurisdictions allow operating losses to be carried forward indefinitely. Capital losses can be carried forward indefinitely.

The valuation allowance decreased by $152.6 million during the year ended December 31, 2017. The change in the valuation allowance was primarily due to $212.1 million decrease as a result of the sale of Peru and Brazil business units. This is partially offset by $86.7 million increase in capital losses generated in Luxembourg as a result of the sale of Brazil, $20.9 million increase in foreign tax credits in the U.S. arising from the U.S. legislated one-time deemed repatriation of foreign earning, $7.1 million increase in tax basis as a result of the 2016 intercompany asset transfers recognized on January 1, 2017, pursuant to adoption of ASU 2016-16 and $10.2 million of losses incurred in the U.S., Colombia and Canada as well as other credits. These future tax benefits are fully off-set by valuation allowances, as their recognition does not meet the "more-likely-than-not" threshold.

The Company and its subsidiaries file income tax returns in U.S. federal and state jurisdictions and certain other foreign jurisdictions. The Company is potentially subject to income tax examinations for open tax years 2009 through 2016 in certain jurisdictions. To the extent interest and penalties may be assessed by taxing authorities on any underpayment of income tax, such amounts have been accrued and are classified as a component of income taxes in the consolidated statement of operations.

On December 23, 2014, the Colombian Congress passed legislation which imposed an equity tax levied on Colombian operations for 2015, 2016 and 2017. The equity tax was calculated based on a legislated measure, which was based on the Company's Colombian legal entities' balance sheet equity for tax purposes at January 1, 2015. This measure was subject to adjustment for inflation in future years. The equity tax rates for January 1, 2015, 2016 and 2017, were 1.15%, 1% and 0.4%, respectively. The legal obligation for each year's equity tax liability arose on January 1 of each year; therefore, the Company recognized the annual amount of $1.2 million, $3.1 million and $3.8 million for the equity tax expense in the consolidated statement of operations for the years ended December 31, 2017, 2016 and 2015. These amounts were paid in May and September of each year and at December 31, 2017, accounts payable included nil (December 31, 2016 - nil).

10. Accounts Payable and Accrued Liabilities

	As at December 31,	
(Thousands of U.S. Dollars)	**2017**	**2016**
Trade	**$ 99,146**	$ 80,072
Royalties	**6,867**	4,542
Employee compensation	**8,767**	8,152
Other	**11,391**	14,285
	$ 126,171	$ 107,051

11. Commitments and Contingencies

Purchase Obligations, Firm Agreements and Leases

As at December 31, 2017, future minimum payments under non-cancelable agreements with remaining terms in excess of one year were as follows:

	Year ending December 31						
	Total	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**
(Thousands of U.S. Dollars)							
Oil transportation services	$ 10,895	$ 3,842	$ 3,842	$ 3,211	$ —	$ —	$ —
Facility construction	27,006	5,446	5,446	5,461	5,446	5,207	—
Operating leases	4,554	1,840	1,267	1,240	207	—	—
Software and telecommunication	961	339	320	302	—	—	—
	$ 43,416	$ 11,467	$ 10,875	$ 10,214	$ 5,653	$ 5,207	$ —

Gran Tierra leases certain office space, compressors, vehicles, equipment and housing. Total rent expense for the year ended December 31, 2017, was $3.2 million (year ended December 31, 2016 – $3.2 million; year ended December 31, 2015 - $4.0 million).

Indemnities

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

Letters of credit

At December 31, 2017, the Company had provided promissory notes totaling $76.0 million (December 31, 2016 - $96.8 million) as security for letters of credit relating to work commitment guarantees contained in exploration contracts and other capital or operating requirements.

Contingencies

The ANH and Gran Tierra are engaged in ongoing discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the HPR royalty. Based on the Company's understanding of the ANH's position, the estimated compensation, which would be payable if the ANH's interpretation is correct, could be up to $50.8 million as at December 31, 2017. At this time, no amount has been accrued in the consolidated financial statements as Gran Tierra does not consider it probable that a loss will be incurred.

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

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

Financial Instruments

At December 31, 2017, the Company's financial instruments recognized in the balance sheet consist of; cash and cash equivalents; restricted cash and cash equivalents; accounts receivable; investments; derivatives; accounts payable and accrued liabilities; long-term debt; PSU liability included in other long-term liabilities; and RSU liability included in accounts payable and accrued liabilities and other long-term liabilities.

Fair Value Measurement

The fair value of investment, derivatives and RSU and PSU liabilities are being remeasured at the estimated fair value at the end of each reporting period.

The fair value of the short-term portion of the investment which was received as consideration on the sale of the Company's Peru business unit was estimated using quoted prices at December 31, 2017 and the market exchange rate at that time. The fair value of the long-term portion of the investment restricted by escrow conditions was estimated using observable and unobservable inputs; factors that were evaluated included quoted market prices, precedent comparable transactions, risk free rate, measures of market risk volatility, estimates of the Company's and Sterling's cost of capital and quotes from third parties.

The fair value of commodity price and foreign currency 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 fair value of the RSU liability was estimated based on quoted market prices in an active market. The fair value of the PSU liability was estimated based on option pricing model using the inputs, such as quoted market prices in an active market, and PSU performance factor.

The fair value of investments, derivatives, RSU, PSU and DSU liabilities at December 31, 2017, and December 31, 2016 were as follows:

	As at December 31,	
(Thousands of U.S. Dollars)	**2017**	**2016**
Investment - current and long-term assets	**$ 44,202**	$ —
Foreign currency derivative asset	**302**	578
	$ 44,504	$ 578
Commodity price derivative liability	**$ 21,151**	$ 3,824
RSU, PSU and DSU liability	**11,430**	3,907
	$ 32,581	$ 7,731

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

(Thousands of U.S. Dollars)	Year Ended December 31,		
	2017	**2016**	**2015**
Commodity price derivative loss	**$ 17,327**	$ 7,370	$ —
Foreign currency derivative (gain) loss	**(1,287)**	(1,016)	692
Investment gain	**(111)**	—	—
Trading securities loss	**—**	3,925	1,335
	$ 15,929	$ 10,279	$ 2,027

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

Investment gain related to fair value gains on the Sterling shares Gran Tierra received in connection with the sale of its Peru business unit in December 2017 (Note 5). For the year ended December 31, 2017 these investment gains were unrealized.

All trading securities were sold during the year ended December 31, 2016, and the trading securities loss represented a realized loss. The cash proceeds were included in cash flows from investing activities in the Company's consolidated statements of cash flows because these securities were received in connection with the sale of the Company's Argentina business unit in 2014. For the year ended December 31, 2015, the trading securities loss represented an unrealized loss.

Financial instruments not recorded at fair value include the Convertible Notes (Note 6). At December 31, 2017, the carrying amount of the Convertible Notes was $111.0 million, which represents the aggregate principal amount less unamortized debt issuance costs, and the fair value was $129.1 million. The fair value of long-term restricted cash and cash equivalents and the revolving credit facility approximated their carrying value because interest rates are variable and reflective of market rates. The fair values of other financial instruments approximate their carrying amounts due to the short-term maturity of these instruments.

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

At December 31, 2017, the fair value of current portion of the investment, RSU and DSU liability was determined using Level 1 inputs, the fair value of derivatives and PSUs was determined using Level 2 inputs and the fair value of the long-term portion of the investment restricted by escrow conditions was determined using Level 3 inputs. The table below presents a roll-forward of the long-term portion of the investment:

	Year Ended December 31,	
(Thousands of U.S. Dollars)	**2017**	**2016**
Opening balance	$ —	$ —
Acquisition	19,091	—
Unrealized gain on valuation	56	—
Closing balance	$ 19,147	$ —

The Company uses available market data and valuation methodologies to estimate the fair value of debt. The fair value of debt is the estimated amount the Company would have to pay a third party to assume the debt, including a 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 Company's Convertible Notes and revolving credit facility to new issuances (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The disclosure in the paragraph above regarding the fair value of the Company's revolving credit facility was determined using an income approach using Level 3 inputs. The disclosure in the paragraph above regarding the fair value of the Convertible Notes was determined using Level 2 inputs based on the indicative pricing published by certain investment banks or trading levels of the Convertible Notes, which are not listed on any securities exchange or quoted on an inter-dealer automated quotation system. The disclosure in the paragraph above regarding the fair value of cash and cash equivalents and restricted cash and cash equivalents was based on Level 1 inputs.

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

Commodity Price Derivatives

The Company utilizes 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.

At December 31, 2017, the Company had outstanding commodity price derivative positions as follows:

Period and type of instrument	**Volume, bopd**	**Reference**	**Sold Swap ($/bbl, Weighted Average)**	**Purchased Call ($/bbl, Weighted Average)**
Swaps: January 1, to December 31, 2018	5,000	ICE Brent	$ 55.90	n/a
Participating Swaps: January 1, to December 31, 2018	5,000	ICE Brent	$ 52.50	$ 56.11

Foreign Exchange Risk and Foreign Currency Derivatives

The Company utilizes foreign currency derivatives to manage the variability in cash flows associated with the Company's forecasted Colombian peso ("**COP**") denominated expenses, predominantly operating costs, general and administrative costs and transportation costs.

At December 31, 2017, the Company had outstanding foreign currency derivative positions as follows:

Period and type of instrument	Amount Hedged (Millions COP)	U.S. Dollar Equivalent of Amount Hedged (Thousands of U.S. Dollars)	Reference	Purchased Call (COP)	Sold Put (COP, Weighted Average)
Collars: January 1, 2018 to December 31, 2018	174,000	58,311	COP	3,000	3,107

The Company's cash flow is only impacted when the actual settlements under the derivative contracts result in making or receiving a payment to or from the counterparty. These cash settlements represent the cumulative gains and losses on the Company's derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled. These cash settlements were included in cash flows from operating activities in the Company's consolidated statements of cash flows.

While the use of these derivative instruments may limit or partially reduce the downside risk of adverse commodity price and foreign exchange movements, their use also may limit future income and gains from favorable commodity price and foreign exchange movements.

Unrealized foreign exchange gains and losses primarily result from fluctuation of the U.S. dollar to the Colombian peso due to Gran Tierra's current and deferred tax liabilities, which are monetary liabilities mainly denominated in the local currency of the Colombian operations. As a result, foreign exchange gains and losses must be calculated on conversion to the U.S. dollar functional currency. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $10,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar. This effect was calculated based on the Company's December 31, 2017, deferred tax balances.

For the year ended December 31, 2017, 98% (year ended December 31, 2016 - 97%, year ended December 31, 2015 - 97%) of the Company's oil and natural gas 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 a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of cash and 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, 2017, 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 uncollateralized sales to customers in the oil and natural gas industry and are exposed to typical industry credit risks. The concentration of revenues in a single industry affects the Company's overall exposure to credit risk because customers may be similarly affected by changes in economic and other conditions. The Company manages this credit risk by entering into sales contracts with only credit worthy entities and reviewing its exposure to individual entities on a regular basis. For the year ended December 31, 2017, the Company had three customers which were significant to the Colombian segment.

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.

13. **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 the same such amounts shown in the consolidated statements of cash flows:

(Thousands of U.S. Dollars)	**As at December 31,**		
	2017	**2016**	**2015**
Cash and cash equivalents	**$ 12,326**	$ 25,175	$ 145,342
Restricted cash and cash equivalents - current	**11,787**	8,322	92
Restricted cash and cash equivalents - long-term[1]	**2,565**	9,770	3,317
	$ 26,678	$ 43,267	$ 148,751

[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,		
	2017	**2016**	**2015**
Accounts receivable and other long-term assets	**$ (2,494)**	$ (29)	$ 44,365
Derivatives	**—**	(3,546)	—
Inventory	**(78)**	5,510	(1,571)
Other prepaids	**2,674**	(615)	152
Accounts payable and accrued and other long-term liabilities	**15,617**	(9,691)	(33,743)
Prepaid tax and taxes receivable and payable	**(44,936)**	(2,966)	(48,251)
Net changes in assets and liabilities from operating activities	**$ (29,217)**	$ (11,337)	$ (39,048)

The following table provides additional supplemental cash flow disclosures:

	Year Ended December 31,		
	2017	**2016**	**2015**
Cash paid for income taxes	**$ 54,505**	$ 64,067	$ 39,422
Cash paid for interest	**$ 9,684**	$ 5,624	$ —
Non-cash investing activities:			
Net liabilities related to property, plant and equipment, end of year	**$ 76,352**	$ 55,181	$ 33,923

See Note 5 in these consolidated financial statements for disclosure regarding non-cash share consideration received in connection with the Company's disposition of its Peru Business unit. In the year ended December 31, 2016, the purchase price paid for acquisition of Petroamerica Oil Corp. included $25.8 million of Gran Tierra's Common Stock.

14. **Subsequent Event**

On February 15, 2018, Gran Tierra Energy International Holdings Ltd., an indirect, wholly owned subsidiary of the Company, issued $300 million aggregate principal amount of its 6.25% Senior Notes due 2025 (the "**2025 Notes**") in a private placement transaction. The 2025 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 2025 Notes will mature on February 15, 2025, unless earlier redeemed or repurchased.

Section B: Financial Statements for the year ended 31 December 2016

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Gran Tierra Energy Inc. and subsidiaries (the "**Company**") as of December 31, 2016 and 2015, and the related consolidated statements of operations, cash flows and shareholders' equity for each of the three years in the period ended December 31, 2016. 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 conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States) and Canadian generally accepted auditing standards. 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Gran Tierra Energy Inc. and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2017 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte LLP

Chartered Professional Accountants
February 28, 2017
Calgary, Canada

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

	Year Ended December 31,		
	2016	**2015**	**2014**
OIL AND NATURAL GAS SALES (NOTE 5)	**$ 289,269**	$ 276,011	$ 559,398
EXPENSES			
Operating	**86,925**	75,565	89,753
Transportation	**31,776**	40,204	24,196
Depletion, depreciation and accretion (Note 5)	**139,535**	176,386	185,877
Asset impairment (Notes 5 and 7)	**616,649**	323,918	265,126
General and administrative (Note 5)	**33,218**	32,353	51,249
Transaction (Note 3)	**7,325**	—	—
Severance (Note 15)	**1,319**	8,990	—
Equity tax (Note 11)	**3,098**	3,769	—
Foreign exchange gain	**(1,469)**	(17,242)	(39,535)
Financial instruments loss (Note 14)	**10,279**	2,027	4,722
Other gain (Note 3)	**(929)**	(502)	(2,000)
Interest expense (Notes 5 and 8)	**14,145**	—	—
	941,871	645,468	579,388
INTEREST INCOME (NOTE 5)	**2,368**	1,369	2,856
LOSS FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (NOTE 5)	**(650,234)**	(368,088)	(17,134)
INCOME TAX (EXPENSE) RECOVERY			
Current (Note 11)	**(20,122)**	(15,383)	(92,865)
Deferred (Note 11)	**204,791**	115,442	(34,350)
	184,669	100,059	(127,215)
LOSS FROM CONTINUING OPERATIONS	**(465,565)**	(268,029)	(144,349)
Loss from discontinued operations, net of income taxes (Note 4)	**—**	—	(26,990)
NET LOSS AND COMPREHENSIVE LOSS	**$ (465,565)**	$ (268,029)	$ (171,339)
NET LOSS PER SHARE - BASIC AND DILUTED BASIC AND DILUTED			
LOSS FROM CONTINUING OPERATIONS	**$ (1.45)**	$ (0.94)	$ (0.51)
LOSS FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	**—**	—	(0.09)
NET LOSS	**$ (1.45)**	$ (0.94)	$ (0.60)
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC AND DILUTED (Note 9)	***320,851,538***	*285,333,869*	*284,715,785*

(*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,	
	2016	**2015**
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 25,175**	$ 145,342
Restricted cash and cash equivalents (Notes 3, 7 and 10)	**8,322**	92
Accounts receivable (Note 6)	**45,698**	29,217
Marketable securities (Note 14)	**—**	6,250
Derivatives (Note 14)	**578**	—
Inventory (Note 6)	**7,766**	19,056
Taxes receivable	**26,393**	28,635
Prepaid taxes (Note 11)	**12,271**	—
Other prepaids	**5,482**	5,848
Total Current Assets	**131,685**	234,440
Oil and Gas Properties (using the full cost method of accounting)		
Proved	**412,319**	469,589
Unproved	**647,774**	310,771
Total Oil and Gas Properties	**1,060,093**	780,360
Other capital assets	**6,516**	8,633
Total Property, Plant and Equipment (Notes 5 and 7)	**1,066,609**	788,993
Other Long-Term Assets		
Deferred tax assets (Note 11)	**1,611**	3,241
Prepaid taxes (Note 11)	**41,784**	—
Other long-term assets	**23,626**	16,863
Goodwill (Note 5)	**102,581**	102,581
Total Other Long-Term Assets	**169,602**	122,685
Total Assets (Note 5)	**$ 1,367,896**	$ 1,146,118
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities (Note 12)	**$ 107,051**	$ 70,778
Derivatives (Note 14)	**3,824**	—
Taxes payable (Note 11)	**38,939**	1,067
Asset retirement obligation (Note 10)	**5,215**	2,146
Total Current Liabilities	**155,029**	73,991
Long-Term Liabilities		
Long-term debt (Notes 8 and 14)	**197,083**	—
Deferred tax liabilities (Note 11)	**107,230**	34,592
Asset retirement obligation (Note 10)	**38,142**	31,078
Other long-term liabilities	**11,425**	4,815
Total Long-Term Liabilities	**353,880**	70,485
Commitments and Contingencies (Note 13)		
Subsequent Events (Note 17)		
Shareholders' Equity		
Common Stock (Note 9) (390,807,194 and 273,442,799 shares of Common Stock and 8,199,894 and 8,572,066 exchangeable shares, par value $0.001 per share, issued and outstanding as at December 31, 2016 and December 31, 2015, respectively)	**10,303**	10,186
Additional paid in capital	**1,342,656**	1,019,863
Deficit	**(493,972)**	(28,407)
Total Shareholders' Equity	**858,987**	1,001,642
Total Liabilities and Shareholders' Equity	**$ 1,367,896**	$ 1,146,118

(*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,		
	2016	**2015**	**2014**
Operating Activities			
Net loss	**$ (465,565)**	$ (268,029)	$ (171,339)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depletion, depreciation and accretion (Note 5)	**139,535**	176,386	185,877
Asset impairment (Notes 5 and 7)	**616,649**	323,918	265,126
Deferred tax (recovery) expense (Note 11)	**(204,791)**	(115,442)	34,350
Stock-based compensation (Note 9)	**6,339**	2,733	6,392
Amortization of debt issuance costs (Note 8)	**5,691**	—	—
Cash settlement of restricted share units	**(1,234)**	(1,392)	(3,371)
Unrealized foreign exchange gain	**(1,428)**	(8,380)	(30,941)
Financial instruments loss (Note 14)	**10,279**	2,027	4,722
Cash settlement of financial instruments	**438**	(3,749)	4,661
Cash settlement of asset retirement obligation (Note 10)	**(605)**	(6,217)	(796)
Other gain (Note 3)	**(929)**	(502)	(2,000)
Equity tax	**—**	—	(3,283)
Loss from discontinued operations, net of income taxes (Note 4)	**—**	—	26,990
Net change in assets and liabilities from operating activities of continuing operations (Note 16)	**(11,337)**	(39,048)	(95,436)
Net cash provided by operating activities of continuing operations	**93,042**	62,305	220,952
Net cash used in operating activities of discontinued operations	**—**	—	(4,792)
Net cash provided by operating activities	**93,042**	62,305	216,160
Investing Activities			
(Increase) decrease in restricted cash	**(236)**	465	(96)
Additions to property, plant and equipment, excluding corporate acquisition (Note 5)	**(127,789)**	(156,639)	(391,526)
Additions to property, plant and equipment - acquisition of PetroGranada (Note 7)	**(19,388)**	—	—
Cash paid for business combinations, net of cash acquired (Note 3)	**(502,643)**	—	—
Proceeds from the sale of oil and gas properties (Note 7)	**6,000**	—	—
Proceeds from sale of marketable securities (Note 14)	**2,325**	—	—
Changes in non-cash investing working capital	**21,116**	(76,844)	44,499
Net cash used in investing activities of continuing operations	**(620,615)**	(233,018)	(347,123)
Proceeds from sale of Argentina business unit, net of cash sold and transaction costs	**—**	—	42,755
Net cash used in investing activities of discontinued operations	**—**	—	(12,384)
Net cash provided by investing activities of discontinued operations	**—**	—	30,371
Net cash used in investing activities	**(620,615)**	(233,018)	(316,752)
Financing Activities			
Proceeds from issuance of shares of Common Stock, net of issuance costs (Note 9)	**128,273**	722	11,140
Proceeds from issuance of subscription receipts, net of issuance costs (Note 9)	**165,805**	—	—
Proceeds from issuance of Convertible Senior Notes, net of issuance costs (Note 8)	**109,090**	—	—
Proceeds from other debt, net of issuance costs (Note 8)	**256,065**	—	—
Repayment of debt (Note 8)	**(252,181)**	—	—
Repurchase of shares of Common Stock (Note 9)	**—**	(9,999)	—
Net cash provided by (used in) financing activities	**407,052**	(9,277)	11,140
Foreign exchange gain (loss) on cash and cash equivalents	**354**	(6,516)	(7,500)
Net decrease in cash and cash equivalents	**(120,167)**	(186,506)	(96,952)
Cash and cash equivalents, beginning of year	**145,342**	331,848	428,800
Cash and cash equivalents, end of year	**$ 25,175**	$ 145,342	$ 331,848
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,		
	2016	**2015**	**2014**
Share Capital			
Balance, beginning of year	**$ 10,186**	$ 10,190	$ 10,187
Issuance of Common Stock (Note 9)	**117**	—	3
Repurchase of Common Stock (Note 9)	**—**	(4)	—
Balance, end of year	**10,303**	10,186	10,190
Additional Paid in Capital			
Balance, beginning of year	**1,019,863**	1,026,873	1,008,760
Issuance of Common Stock, net of share issuance costs (Note 9)	**314,425**	—	—
Exercise of stock options (Note 9)	**5,347**	722	11,137
Stock-based compensation (Note 9)	**3,021**	2,263	6,976
Repurchase of Common Stock (Note 9)	**—**	(9,995)	—
Balance, end of year	**1,342,656**	1,019,863	1,026,873
Retained Earnings (Deficit)			
Balance, beginning of year	**(28,407)**	239,622	410,961
Net loss	**(465,565)**	(268,029)	(171,339)
Balance, end of year	**(493,972)**	(28,407)	239,622
Total Shareholders' Equity	**$ 858,987**	$ 1,001,642	$ 1,276,685

(*See notes to the consolidated financial statements*)

15. Description of Business

Gran Tierra Energy Inc., a Delaware corporation (the "**Company**" or "**Gran Tierra**"), is a publicly traded company focused on oil and natural gas exploration and production in Colombia. The Company also has business activities in Peru and Brazil, and until June 25, 2014, had business activities in Argentina. On February, 6, 2017, the Company announced that a purchase and sale agreement (the "**Agreement**") had been executed by a third party ("**Purchaser**") to purchase Gran Tierra's Brazil business unit through the acquisition of all of the equity interests in one of Gran Tierra's indirect subsidiaries, and the assignment of certain debt owed by the corporate entities comprising Gran Tierra's Brazil business unit to the Gran Tierra group of companies (Note 17).

16. Significant Accounting Policies

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

Significant accounting policies are:

Basis of consolidation

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

Discontinued operations

On June 25, 2014, the Company completed the sale of its Argentina business unit and the discontinued operations criteria of Accounting Standards Codification ("**ASC**") 205-20, "Discontinued Operations", were met. Therefore, the results of the Company's Argentina business unit are reflected separately as loss from discontinued operations, net of income taxes, in the consolidated statement of operations for the year ended December 31, 2014, on a line immediately after "Loss or income from continuing operations." Additionally, cash flows of the Company's Argentina business unit are reflected separately in the consolidated statement of cash flows for the year ended December 31, 2014, as cash provided by or used in operating and investing activities of discontinued operations. See Note 4, "Discontinued Operations," for additional disclosure.

Use of estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates made by management include: oil and natural gas reserves and related present value of future cash flows; depreciation, depletion, amortization and impairment ("**DD&A**"); impairment assessments of goodwill; timing of transfers from oil and gas properties not subject to 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 is included in other current assets and other long-term assets on the Company's balance sheet. Restricted cash and cash equivalents comprises cash and cash equivalents pledged to secure letters of credit and to settle asset retirement obligations. Letters of credit currently secured by cash relate to work commitment guarantees contained in exploration contracts. 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.

Allowance for doubtful accounts

The Company estimates losses on receivables based on known uncollectible accounts, if any, and historical experience of losses incurred and accrues a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated. The allowance for doubtful receivables was $nil at December 31, 2016, and 2015.

Marketable securities

The Company acquired investments in marketable securities in connection with the sale of its Argentina business unit in 2014. Marketable securities are classified as trading securities, in accordance with ASC 320, "*Investments – Debt and Equity Securities*", and are recorded in the consolidated balance sheet at fair value. The Company classifies trading securities as current or non-current based on the intent of management, the nature of the trading securities and whether they are readily available for use in current operations. Gains or losses on trading securities are recorded in the consolidated statement of operations as financial instruments gains or losses.

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. 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 or market value. The cost of inventory is determined using the weighted average method. Oil inventories include expenditures incurred to produce, upgrade and transport the product to the storage facilities and include operating, depletion and depreciation expenses and cash royalties.

Income taxes

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

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

Oil and gas properties

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

The Company computes depletion of oil and natural gas properties on a quarterly basis using the unit-of-production method based upon production and estimates of proved reserve quantities. Future development costs related to properties with proved reserves are also included in the amortization base for computation of depletion. The costs of unproved properties are excluded from the amortization 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 results in a lower DD&A rate in future periods. A write-down may not be reversed in future periods even though higher oil and natural gas prices may subsequently increase the ceiling.

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

Unproved properties are not depleted pending the determination of the existence of proved reserves. Costs are transferred into the depletable base on an ongoing basis as the properties are evaluated and proved reserves are established or impairment is determined. Unproved properties are evaluated quarterly to ascertain whether impairment has occurred. This evaluation considers, among other factors, seismic data, requirements to relinquish acreage, drilling results and activity, remaining time in the commitment period, remaining capital plans, and political, economic, and market conditions. During any period in which factors indicate an impairment, the cumulative costs incurred to date for such property are transferred to the full cost pool and are then subject to 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 are 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 and automobiles. Depreciation is provided using the declining-balance method at a 30% annual rate for furniture and fixtures, computer equipment and automobiles. Leasehold improvements are depreciated on a straight-line basis over the shorter of the estimated useful life and the term of the related lease. The cost of repairs and maintenance is charged to expense as incurred.

Goodwill

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

The Company recorded $87.6 million of goodwill in relation to the acquisition of Solana Resources Limited ("**Solana**") in 2008 and $15.0 million of goodwill in relation to the Argosy Energy International L.P. acquisition in 2006. The goodwill relates entirely to the Colombia reportable segment. The Company performed a qualitative assessment of goodwill at December 31, 2016, and based on this assessment, no impairment of goodwill was identified.

Convertible Senior Notes

The Company accounts for its 5.00% Convertible Senior Notes due 2021 (the "**Notes**") as a liability in their entirety. The embedded features of the Notes were assessed for bifurcation from the Notes under the applicable provisions, including the basic conversion feature, the fundamental change make-whole provision and the put and call options. Based on an assessment, the Company concluded that these embedded features did not meet the criteria to be accounted for separately.

The Company incurred debt issuance costs in connection with the issuance of the Notes which have been presented as a direct deduction against the carrying amount of the Notes and are being amortized to interest expense using the effective interest method over the contractual term of the Notes.

Revenue recognition

Revenue from the production of oil and natural gas is recognized when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable, the sale is evidenced by a contract and collection of the revenue is reasonably assured. In Colombia, the sales point for the

Company's sales varies depending on the delivery point but includes the Port of Tumaco on the Pacific coast of Colombia, the purchaser's facilities and when oil is loaded into a truck at Gran Tierra's loading facility or an export tanker. In Brazil, the sales point is either the Petróleo Brasileiro S.A station or the purchaser's facility.

Revenue represents the Company's share and is recorded net of royalty payments to governments and other mineral interest owners.

Stock-based compensation

The Company 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.

Loss per share

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

Recently Adopted Accounting Pronouncements

Simplifying the Accounting for Measurement - Period Adjustments

In September 2015, the Financial Accounting Standards Board (the "**FASB**") issued Accounting Standards Update ("**ASU**") 2015-16, "Simplifying the Accounting for Measurement - Period Adjustments". The amendments require that an acquirer recognize adjustments to provisional amounts identified during the measurement period in the reporting period in which the adjustments are determined and eliminates the requirement to retrospectively revise prior periods. Additionally, an acquirer should record in the same period the effects on earnings of any changes in the provisional accounts, calculated as if the accounting had been completed at the acquisition date. The ASU was effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. The implementation of this update did not materially impact the Company's consolidated financial position at December 31, 2016 or results of operations or cash flows for the year ended December 31, 2016. See Note 3, "Business Combinations," for additional disclosure.

Classification of Certain Cash Receipts and Cash Payments

In August 2016, the FASB issued ASU 2016-15, "Classification of Certain Cash Receipts and Cash Payments". This ASU addresses specific cash flow issues with the objective of reducing the existing diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. The ASU will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. The Company implemented this update retrospectively in its consolidated financial statements for the interim period ended September 30, 2016. The implementation of this update did not materially impact the Company's consolidated financial position, results of operations or cash flows or disclosure.

Recently Issued Accounting Pronouncements

Revenue from Contracts with Customers

In May 2014, the FASB issued guidance regarding the accounting for revenue from contracts with customers. In August 2015, the FASB issued ASU 2015-14, "Revenue from Contracts with Customers - Deferral of the Effective Date". The ASU deferred the effective date of the new revenue recognition model by one year. As a result, the guidance will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2017.

In March 2016, the FASB issued ASU 2016-08, "Principal versus Agent Considerations (Reporting Revenue Gross versus Net)" which clarifies implementation guidance on principal versus agent considerations. In April, May and December 2016, the FASB issued ASU 2016-10, "Identifying Performance Obligations and Licensing", ASU 2016-12, "Narrow-Scope Improvements and Practical Expedients" and ASU 2016-20 "Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers", respectively, which addressed implementation issues and provided technical corrections.

The guidance may be applied retrospectively or using a modified retrospective approach to adjust retained earnings. The Company is currently assessing the impact the new revenue recognition model will have on its consolidated financial position, results of operations, cash flows, and disclosure.

Simplifying the Measurement of Inventory

In July 2015, the FASB issued ASU 2015-11, "Simplifying the Measurement of Inventory". The ASU provides guidance for the subsequent measurement of inventory and requires that inventory that is measured using average cost be measured at the lower of cost and net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The ASU will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. The implementation of this update is not expected to materially impact the Company's consolidated financial position, results of operations or cash flows or disclosure.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU 2016-01, "Recognition and Measurement of Financial Assets and Financial Liabilities". ASU 2016-01 addresses certain aspects of recognition, measurement, presentation and disclosure of financial instruments. ASU 2016-01 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2017. This ASU is not expected to have a material impact on the Company's consolidated financial position, results of operations or cash flows or disclosure.

Leases

In February 2016, the FASB issued ASU 2016-02, "Leases". This ASU will require most lease assets and lease liabilities to be recognized on the balance sheet and the disclosure of key information about lease arrangements. The ASU will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2018. The Company is currently assessing the impact the new lease standard will have on its consolidated financial position, results of operations, cash flows, and disclosure.

Employee Share-Based Payment Accounting

In March 2016, the FASB issued ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting". This ASU simplifies several aspects of the accounting for employee share-based payment transactions, including the accounting for forfeitures, income taxes, and statutory tax withholding requirements. The ASU will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. The Company is currently assessing the impact this update will have on its consolidated financial position, results of operations, cash flows, and disclosure.

Financial Instruments **-** *Credit Losses*

In June 2016, the FASB issued ASU 2016-13, "Financial Instruments - Credit Losses". This ASU replaces the current incurred loss impairment methodology with a methodology that reflects expected credit losses and requires a broader range of reasonable and supportable information to support credit loss estimates. The ASU will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2019. The Company is currently assessing the impact this update will have on its consolidated financial position, results of operations, cash flows, and disclosure.

Income Taxes **-** *Intra-Entity Transfers of Assets Other than Inventory*

In October 2016, the FASB issued ASU 2016-16, "Intra-Entity Transfers of Assets Other than Inventory". This ASU requires companies to recognize the income tax effects of intercompany sales or transfers of assets, other than inventory, in the income statement as income tax expense or benefit in the period the sale or transfer occurs. Current GAAP prohibits the recognition of income tax expense or benefit for an intra-entity transfer until the asset leaves the consolidated group.

This ASU will be effective for fiscal years beginning after December 15, 2017, and interim periods within those years. Early adoption is permitted as of the beginning of an annual reporting period. The ASU must be applied on a modified retrospective basis with a cumulative-effect adjustment directly to retained earnings in the period of adoption. In the period of adoption, the Company will write off any income tax effects that had been deferred from past intercompany transactions to opening retained earnings.

The Company expects to early adopt this ASU in its year ended December 31, 2017, and expects prepaid tax of $54.1 million and deferred tax assets will be recorded directly to opening retained earnings at January 1, 2017. The Company is currently assessing the deferred tax effect of adoption of this ASU. Deferred tax assets recorded upon adoption will be assessed for realizability under ASC 740, and, if a valuation allowance on those deferred tax assets is necessary on the date of adoption, that allowance will be recorded with an offset to opening retained earnings. ASU 2016-16 will not have any effect on the Company's cash flows.

Restricted Cash

In November 2016, the FASB issued ASU 2016-18, "Restricted Cash". ASU 2016-18 requires that a statement of cash flows explain the change during the period in the total cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents. ASU 2016-18 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2017. This ASU will not impact the Company's consolidated financial position or results of operations and for the year ended December 31, 2016, would not have had a material impact on net cash used in investing activities. For the year ended December 31, 2016, the net decrease in cash, cash equivalents and restricted cash and cash equivalents would have been $119.9 million, compared with the net decrease in cash and cash equivalents of -$120.2 million as currently disclosed in the consolidated statement of cash flows.

Clarifying the Definition of a Business

In January 2017, the FASB issued ASU 2017-01, "Clarifying the Definition of a Business". ASU 2017-01 narrows the definition of a business and provides a framework that gives entities a basis for making reasonable judgments about whether a transaction involves an asset or a business. ASU 2017-01 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2017. Early adoption is permitted.

The Company expects to early adopt this ASU in its year ended December 31, 2017. The Company will apply an initial screen for determining whether a transaction involves an asset or a business. When substantially all of the fair value of the gross assets acquired is concentrated in a single identified asset, the set will not be a business and no goodwill or gain on acquisition will be recognized.

Simplifying the Test for Goodwill Impairment

In January 2017, the FASB issued ASU 2017-04, "Simplifying the Test for Goodwill Impairment". ASU 2017-04 eliminates step 2 of the goodwill impairment test. An entity no longer will determine goodwill impairment by calculating the implied fair value of goodwill by assigning the fair value of a reporting unit to all of its assets and liabilities as if that reporting unit had been acquired in a business combination. A goodwill impairment will now be the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill. ASU 2017-04 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2019. Early adoption is permitted. At December 31, 2016, the Company performed a qualitative assessment of goodwill and, based on this assessment, no impairment of goodwill was identified. The Company did not have to perform step 2 of the goodwill impairment test.

17. Business Combinations

(a) *PetroLatina Energy Ltd.*

On August 23, 2016 (the "**PetroLatina Acquisition Date**"), the Company acquired all of the issued and outstanding common shares of PetroLatina Energy Ltd. ("**PetroLatina**") for $525 million, consisting of cash consideration of $465.7 million, which included a deferred cash payment of $25.0 million that was paid on December 31, 2016, assumption of a reserve-backed credit facility with an outstanding balance of $80.0 million (Note 8), net working capital of $17.3 million and other closing adjustments. Upon completion of the transaction on the PetroLatina Acquisition Date, Gran Tierra repaid and canceled the reserve-based credit facility and PetroLatina became an indirect wholly-owned subsidiary of Gran Tierra.

PetroLatina is an exploration and production company, incorporated in England and Wales, with assets primarily in the Middle Magdalena Basin of Colombia. The acquisition added a new core area for Gran Tierra in the prolific Middle Magdalena Basin and was accounted for as a business combination using the acquisition method, with Gran Tierra being the acquirer, whereby the assets acquired and liabilities assumed were recognized at their fair values as at the PetroLatina Acquisition Date, and the results of PetroLatina were included with those of Gran Tierra from that date. Fair value estimates were made based on significant unobservable (Level 3) inputs and based on the best information available at the time.

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

(Thousands of U.S. Dollars)		
Consideration Paid:		
Purchase price	$	525,000
Purchase price adjustments:		
PetroLatina's long-term debt assumed		(80,000)
Working capital and other		20,683
Total cash consideration		465,683
Estimated post-closing adjustments		1,908
Cash consideration paid	$	467,591
Allocation of Total Consideration[(2)]:		
Oil and gas properties		
Proved[(1)]	$	360,483
Unproved[(1)]		432,286
Net working capital (including cash acquired of $15.9 million, restricted cash of $0.7 million and accounts receivable of $4.0 million)		17,302
Long-term restricted cash		3,017
Long-term debt		(80,000)
Long-term deferred tax liability[(1)]		(262,566)
Long-term portion of asset retirement obligation		(3,870)
Other long-term liabilities		(969)
	$	465,683

(1) During the three months ended December 31, 2016, post-closing adjustments were finalized and this resulted in a $4.3 million increase to total cash consideration. Additionally, management obtained further information about the acquisition date fair value of PetroLatina's proved and unproved properties and working capital and determined that the fair values were $3.9 million lower, $9.6 million higher and $1.8 million higher, respectively, than previously estimated. This resulted in a $3.2 million increase in the acquisition date deferred tax liability. In accordance with GAAP, these changes were accounted for in the three months ended December 31, 2016 without retrospective revision of prior periods. The reduction in the acquisition date fair value of proved properties would have resulted in a $1.0 million net of income tax expense, reduction in the net loss for the three months ended September 30, 2016, as a result of lower Colombian ceiling test impairment losses.

(2) The allocation of the consideration is incomplete and is subject to change. Management is continuing to review and assess information to accurately determine the acquisition date fair value of the assets and liabilities acquired. During the measurement period, Gran Tierra will continue to obtain information to assist in finalizing the fair value of net assets acquired, which may differ materially from the above preliminary estimates.

The Company's consolidated statement of operations for the year ended December 31, 2016, included oil and gas sales of $11.4 million and net loss after tax of $42.3 million from PetroLatina for the period subsequent to the PetroLatina Acquisition Date.

Pro Forma Results (unaudited)

Pro forma results for the years ended December 31, 2016 and 2015, are shown below, as if the acquisition had occurred on January 1, 2015. Pro forma results are not indicative of actual results or future performance.

	Years Ended December 31,			
(Unaudited, thousands of U.S. Dollars, except per share amounts)		**2016**		**2015**
Oil and gas sales	**$**	**323,266**	$	357,693
Net loss	**$**	**(309,972)**	$	(288,389)
Net loss per share - basic and diluted	**$**	**(0.97)**	$	(1.01)

The supplemental pro forma net loss of Gran Tierra for the year ended December 31, 2016, was adjusted to exclude $6.2 million of transaction expenses because they were not expected to have a continuing impact on Gran Tierra's results of operations.

(b) ***Petroamerica Oil Corp.***

On January 13, 2016 (the "**Petroamerica Acquisition Date**"), the Company acquired all of the issued and outstanding common shares of Petroamerica Oil Corp. ("**Petroamerica**"), a Canadian corporation, pursuant to the terms and conditions of an arrangement agreement dated November 12, 2015 (the "**Arrangement**"). The transaction contemplated by the Arrangement was effected through a court approved plan of arrangement in Canada. The Arrangement was approved at a special meeting of Petroamerica shareholders and by the Court of Queen's Bench of Alberta on January 11, 2016. Under the Arrangement, each Petroamerica shareholder was entitled to receive, for each Petroamerica share held, either $0.40 of a Gran Tierra common share or $1.33 Canadian dollars in cash, or a combination of shares and cash, subject to a maximum of 70% of the consideration payable in cash.

As consideration for the acquisition of all the issued and outstanding Petroamerica shares, the Company issued approximately 13.7 million shares of Gran Tierra Common Stock, par value $0.001, and paid cash consideration of approximately $70.6 million. The fair value of Gran Tierra's Common Stock issued was determined to be $25.8 million based on the closing price of shares of Common Stock of Gran Tierra as at the Petroamerica Acquisition Date. Total net purchase price of Petroamerica was $72.2 million, after giving effect to net working capital of $24.2 million. Upon completion of the transaction on the Petroamerica Acquisition Date, Petroamerica became an indirect wholly-owned subsidiary of Gran Tierra.

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

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

(Thousands of U.S. Dollars)		
Consideration Paid:		
Cash	$	70,625
Issuance of Common Shares, net of share issuance costs		25,811
	$	96,436
Allocation of Consideration Paid:		
Oil and gas properties		
Proved[(1)]	$	36,082
Unproved[(1)]		52,232
Net working capital (including cash acquired of $19.7 million, restricted cash of $2.5 million and accounts receivable of $5.0 million)		24,202
Long-term restricted cash		8,167
Other long-term assets		1,570
Long-term deferred tax liability[(1)]		(10,553)
Long-term portion of asset retirement obligation		(11,556)
Other long-term liabilities		(2,779)
Gain on acquisition[(1)]		(929)
	$	96,436

[(1)] During the three months ended December 31, 2016, management obtained further information about the acquisition date fair value of Petroamerica's proved and unproved properties and determined that the fair values were $12.5 million lower and $2.2 million higher, respectively, than previously estimated. This resulted in a $10.8 million decrease in the gain on acquisition, and a $0.5 million increase in the acquisition date deferred tax liability. In accordance with GAAP, these changes were accounted for in the three months ended December 31, 2016 without retrospective revision of prior periods. The reduction in the acquisition date fair value of proved properties would have resulted in a $11.4 million, net of income tax expense, reduction in the net loss for the three months ended March 31, 2016, as a result of lower Colombian ceiling test impairment losses.

As indicated in the allocation of the consideration paid, the fair value of identifiable assets acquired and liabilities assumed exceeded the fair value of the consideration paid. Consequently, Gran Tierra reassessed the recognition and measurement of identifiable assets acquired and liabilities assumed and concluded that all acquired assets and assumed liabilities were recognized and that the valuation procedures and resulting measures were appropriate. As a result, Gran Tierra recognized an "Other gain" of $0.9 million in the consolidated statement of operations for the year ended December 31, 2016. The gain reflects the impact on Petroamerica's pre-acquisition market value resulting from the company's lack of liquidity and capital resources required to maintain current production and reserves and further develop and explore their inventory of prospects.

The Company's consolidated statement of operations for the year ended December 31, 2016, included oil and gas sales of $17.1 million and net loss after tax of $24.7 million from Petroamerica for the period subsequent to the Petroamerica Acquisition Date.

Pro Forma Results (unaudited)

Pro forma results for the years ended December 31, 2016 and 2015, are shown below, as if the acquisition had occurred on January 1, 2015. Pro forma results are not indicative of actual results or future performance.

	Year Ended December 31,	
(Unaudited, thousands of U.S. Dollars, except per share amounts)	**2016**	**2015**
Oil and gas sales	**$ 289,739**	$ 332,867
Net loss	**$ (466,506)**	$ (276,852)
Net loss per share - basic and diluted	**$ (1.45)**	$ (0.97)

The supplemental pro forma net loss of Gran Tierra for the year ended December 31, 2016, was adjusted to exclude the $0.9 million gain on acquisition and $1.2 million of transaction expenses because they were not expected to have a continuing impact on Gran Tierra's results of operations.

18. Discontinued Operations

On June 25, 2014, the Company sold its Argentina business unit to Madalena Energy Inc. ("**Madalena**") for aggregate consideration of $69.3 million, comprising $55.4 million in cash and $13.9 million in Madalena shares. Revenue and other income and loss from discontinued operations, net of income taxes, for the year ended December 31, 2014, were as follows:

	Year Ended December 31,
(Thousands of U.S. Dollars)	**2014**
(Revenue and other income	$ 31,985
Loss from operations of discontinued operations before income taxes	$ (6,252)
Income tax expense	(1,458)
Loss from operations of discontinued operations	(7,710)
Loss on sale before income taxes	(18,235)
Income tax expense	(1,045)
Loss on sale	(19,280)
Loss from discontinued operations, net of income taxes	$ (26,990)

19. Segment and Geographic Reporting

The Company is primarily engaged in the exploration and production of oil and natural gas. The Company's reportable segments are Colombia, Peru and Brazil based on geographic organization. The All Other category represents the Company's corporate activities. The Company evaluates reportable segment performance based on income or loss from continuing operations before income taxes.

On February 6, 2017, the Company announced that a purchase and sale agreement had been executed by the Purchaser to purchase Gran Tierra's Brazil business unit through the acquisition of all of the equity interests in one of Gran Tierra's indirect subsidiaries, and the assignment of certain debt owed by the corporate entities comprising Gran Tierra's Brazil business unit to the Gran Tierra group of companies (Note 17). The completion of the sale is subject to the Purchaser obtaining financing, as well as customary closing conditions, including the receipt of required regulatory approval from the ANP.

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

	Year Ended December 31, 2016				
(Thousands of U.S. Dollars)	**Colombia**	**Peru**	**Brazil**	**All Other**	**Total**
Oil and natural gas sales	**$ 280,872**	**$ —**	**$ 8,397**	**$ —**	**$ 289,269**
DD&A expenses	**132,569**	**544**	**3,819**	**2,603**	**139,535**
Asset impairment	**514,314**	**31,192**	**71,143**	**—**	**616,649**
General and administrative expenses	**17,187**	**1,643**	**968**	**13,420**	**33,218**
Interest income	**1,281**	**8**	**274**	**805**	**2,368**
Interest expense	**—**	**—**	**—**	**14,145**	**14,145**
Loss from continuing operations before income taxes	**(505,447)**	**(33,181)**	**(70,591)**	**(41,015)**	**(650,234)**
Segment capital expenditures[1]	**105,963**	**5,059**	**15,146**	**1,621**	**127,789**

	Year Ended December 31, 2015				
(Thousands of U.S. Dollars)	**Colombia**	**Peru**	**Brazil**	**All Other**	**Total**
Oil and natural gas sales	$ 269,035	$ —	$ 6,976	$ —	$ 276,011
DD&A expenses	167,701	789	6,183	1,713	176,386
Asset impairment	235,069	41,916	46,933	—	323,918
General and administrative expenses	9,805	3,800	2,708	16,040	32,353
Interest income	294	2	218	855	1,369
Interest expense	—	—	—	—	—
Loss from continuing operations before income taxes	(238,463)	(51,675)	(54,968)	(22,982)	(368,088)
Segment capital expenditures	85,326	50,203	20,014	1,096	156,639

	Year Ended December 31, 2014				
(Thousands of U.S. Dollars)	**Colombia**	**Peru**	**Brazil**	**All Other**	**Total**
Oil and natural gas sales	$ 532,196	$ —	$ 27,202	$ —	$ 559,398
DD&A expenses	174,063	690	9,932	1,192	185,877
Asset impairment	—	265,126	—		265,126
General and administrative expenses	19,431	6,448	3,698	21,672	51,249
Interest income	569	1	1,604	682	2,856
Interest expense	—	—	—	—	—
Income (loss) from continuing operations before income taxes	279,924	(274,207)	5,921	(28,772)	(17,134)
Segment capital expenditures	206,520	158,266	23,873	2,867	391,526

[1] On January 13, 2016 and August 23, 2016, respectively, the Company acquired all of the issued and outstanding common shares of Petroamerica and PetroLatina, which acquisitions were accounted for as business combinations (Note 3) and, therefore, property, plant and equipment acquired are not reflected in the table above. Additionally, on January 25, 2016, the Company acquired all of the issued and outstanding common shares of PetroGranada Colombia Limited ("**PGC**"), which acquisition was accounted for as an asset acquisition (Note 7) and property, plant and equipment acquired in this acquisition are not reflected in the table above.

(Thousands of U.S. Dollars)	As at December 31, 2016 Colombia	Peru	Brazil	All Other	Total
Property, plant and equipment	**$ 939,947**	**$ 68,428**	**$ 55,196**	**$ 3,038**	**$1,066,609**
Goodwill	**102,581**	**—**	**—**	**—**	**$ 102,581**
All other assets	**177,393**	**10,848**	**1,619**	**8,846**	**$ 198,706**
Total Assets	**$1,219,921**	**$ 79,276**	**$ 56,815**	**$ 11,884**	**$1,367,896**

(Thousands of U.S. Dollars)	As at December 31, 2015 Colombia	Peru	Brazil	All Other	Total
Property, plant and equipment	$ 574,351	$ 95,069	$ 115,552	$ 4,021	$ 788,993
Goodwill	102,581	—	—	—	$ 102,581
All other assets	93,479	21,111	2,236	137,718	$ 254,544
Total Assets	$ 770,411	$ 116,180	$ 117,788	$ 141,739	$1,146,118

The following table presents the number of customers from whom the Company derived 10% or more of its consolidated oil and gas sales and sales as a percentage of the Company's consolidated oil and gas sales to each customer. All of these customers were in the Company's Colombian reportable segment:

	Year Ended December 31, 2016	2015	2014
Number of significant customers	**3**	4	2
Sales to each significant customer as % of oil and gas sales	**40% 34% 13%**	43% 15% 13% 12%	52% 32%

20. **Accounts Receivable and Inventory**

Accounts Receivable

(Thousands of U.S. Dollars)	As at December 31, 2016	2015
Trade	**$ 39,203**	$ 26,924
Other	**6,495**	2,293
	$ 45,698	$ 29,217

Inventory

At December 31, 2016, oil and supplies inventories were $6.0 million and $1.8 million, respectively (December 31, 2015 - $17.8 million and $1.3 million, respectively). At December 31, 2016, the Company had 208 Mbbl of oil inventory (December 31, 2015 - 616 Mbbl) NAR. In the year ended December 31, 2016, the Company recorded oil inventory impairment of $0.7 million (year ended December 31, 2015 - $2.6 million, year ended December 31, 2014 - $nil) related to lower oil prices (Note 7).

21. **Property, Plant and Equipment**

(Thousands of U.S. Dollars)	As at December 31, 2016	2015
Oil and natural gas properties		
Proved	**$ 2,652,171**	$ 1,998,330
Unproved	**647,774**	310,771
	3,299,945	2,309,101
Other	**29,445**	28,342
	3,329,390	2,337,443
Accumulated depletion, depreciation and impairment	**(2,262,781)**	(1,548,450)
	$ 1,066,609	$ 788,993

In the year ended December 31, 2016, the Company recorded ceiling test impairment losses of $513.7 million in its Colombia cost center, and $71.1 million in its Brazil cost center. The Colombia ceiling test impairment loss related to lower oil prices and the fact that the acquisitions of PetroLatina and PetroAmerica were initially added into the cost base at estimated fair value (Note 3). However, these acquired assets were subjected to a prescribed U.S. GAAP ceiling test, which is not a fair value test, and which, as noted below, uses constant commodity pricing that averages prices during the preceding 12 months. The Brazil ceiling test impairment loss related to continued low oil prices and increased costs in the depletable base as a result of a $45.0 million impairment of unproved properties.

In the year ended December 31, 2015, the Company recorded ceiling test impairment losses of $232.4 million in its Colombia cost center, and $46.9 million in its Brazil cost center as a result of lower realized prices.

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 during the 12 months period prior to the ending date of the period covered by the balance sheet, calculated as an unweighted arithmetic average of the first-day-of-the month price for each month within such period for that oil and natural gas. That average price is then held constant, except for changes which are fixed and determinable by existing contracts. 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 the Company's reserves. In accordance with GAAP, Gran Tierra used an average Brent price of $42.92 per bbl for the purposes of the December 31, 2016, ceiling test calculations (December 31, 2015 - $54.08).

In the year ended December 31, 2016, the Company recorded impairment losses in its Peru cost center of $31.2 million related to costs incurred on Block 95, and other blocks. In the years ended December 31, 2015 and 2014, the Company recorded impairment losses of $41.9 million and $265.1 million, respectively, related to costs incurred on Block 95. On February 19, 2015, the Company made the decision to cease all further development expenditures on the Bretaña Field on Block 95 other than what is necessary to maintain tangible asset integrity and security. In the three months ended September 30, 2016, the Company ceased the impairment of costs incurred on Block 95 as a result of the effect of a revised field development plan for the Block.

Asset impairment for the three years ended December 31, 2016, was follows:

(Thousands of U.S. Dollars)	Year Ended December 31, 2016	2015	2014
Impairment of oil and gas properties	**$ 615,985**	$ 321,285	$ 265,126
Impairment of inventory (Note 6)	**664**	2,633	—
	$ 616,649	$ 323,918	$ 265,126

Depletion and depreciation expense on property, plant and equipment for the year ended December 31, 2016, was $130.2 million (year ended December 31, 2015 - $177.9 million; year ended December 31, 2014 - $187.9 million). A portion of depletion and depreciation expense was recorded as inventory in each year and adjusted for inventory changes.

Acquisition of PGC

On January 25, 2016, the Company acquired all of the issued and outstanding common shares of PGC, pursuant to the terms and conditions of an acquisition agreement dated January 14, 2016. PGC is an oil and gas exploration, development and production company active in Colombia. Upon completion of the transaction, PGC became an indirect wholly-owned subsidiary of Gran Tierra. The net purchase price of PGC was $19.4 million, after giving consideration to net working capital of $18.3 million. The acquisition was accounted for as an asset acquisition with the excess consideration paid over the fair value of the net assets acquired allocated on a relative fair value basis to the net assets acquired.

The following table shows the allocation of the cost of the acquisition based on the relative fair values of the assets and liabilities acquired:

(Thousands of U.S. Dollars)		
Cost of asset acquisition:		
Cash	$	37,727
Allocation of Consideration Paid:		
Oil and gas properties		
Proved	$	12,228
Unproved		15,563
		27,791
Net working capital (including cash acquired of $0.2 million and restricted cash of $18.6 million)		18,339
Long-term deferred tax liability		(8,403)
	$	37,727

Contingent consideration of $4.0 million will be payable if cumulative production from the Putumayo-7 Block plus gross proved plus probable reserves under the Putumayo-7 Block meet or exceed 8 MMbbl. Contingent consideration will be recognized when the contingency is resolved and the consideration is paid or becomes payable.

On November 25, 2016, Gran Tierra submitted winning bids totaling a combined $30.4 million for two blocks which Ecopetrol offered as part of an asset disposition process. Gran Tierra's winning bids were on the Santana and Nancy-Burdine-Maxine Blocks, which are located in the Putumayo Basin. At December 31, 2016, the assignments of working interests in these blocks was not complete. Ecopetrol will transfer ownership of the blocks' assets, contracts, permits and licenses, as well as 100% ownership of Ecopetrol's rights and obligations in respect of the oil and gas assets, to Gran Tierra once the Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) ("**ANH**") grants approval and the conditions of the assignment agreement are met. The purchase price of $30.4 million will be paid from the Company's credit facility. Additionally, Gran Tierra sold non-operated and non-core assets in Colombia to a third party for cash consideration of $6.0 million.

Unproved oil and natural gas properties consist of exploration lands held in Colombia, Brazil and Peru. The following table provides a summary of Gran Tierra's unproved properties as at December 31, 2016:

	As at December 31,			
(Thousands of U.S. Dollars)		**2016**		**2015**
Colombia	**$**	**561,463**	$	147,500
Brazil		**67,866**		69,089
Peru		**18,445**		94,182
	$	**647,774**	$	310,771

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 74% of costs not subject to depletion at December 31, 2016, will be transferred to the depletable base within the next five years and the remainder in the next five to 10 years.

The following is a summary of Gran Tierra's oil and natural gas properties not subject to depletion as at December 31, 2016:

	Costs Incurred in				
(Thousands of U.S. Dollars)	**2016**	**2015**	**2014**	**Prior to 2014**	**Total**
Acquisition costs - Colombia	**$ 429,626**	**$ —**	**$ —**	**$ 48,810**	**$478,436**
Acquisition costs - Peru	**—**	**—**	**—**	**11,500**	**11,500**
Acquisition costs - Brazil	**—**	**—**	**—**	**5,949**	**5,949**
Exploration costs - Colombia	**10,823**	**16,840**	**29,969**	**25,394**	**83,026**
Exploration costs - Peru	**3,213**	**7,471**	**29,424**	**16,258**	**56,366**
Exploration costs - Brazil	**79**	**4,714**	**2,024**	**5,680**	**12,497**
Total oil and natural gas properties not subject to depletion	**$ 443,741**	**$ 29,025**	**$ 61,417**	**$ 113,591**	**$647,774**

22. **Debt and Debt Issuance Costs**

The Company's debt at December 31, 2016 and 2015, was as follows:

	As at December 31,	
(Thousands of U.S. Dollars)	**2016**	**2015**
Convertible senior notes (a)	**$ 115,000**	$ —
Revolving credit facility (b)	**90,000**	—
Unamortized debt issuance costs	**(7,917)**	—
Long-term debt	**$ 197,083**	$ —

(a) ***Convertible Senior Notes***

On April 6, 2016, the Company issued $100 million aggregate principal amount of Notes in a private placement to qualified institutional buyers. On April 22, 2016, the Company issued an additional $15 million aggregate principal amount of the Notes pursuant to the underwriters' exercise of their option to acquire additional Notes. The Notes bear interest at a rate of 5.00% per year, payable semi-annually in arrears on April 1 and October 1 of each year, beginning on October 1, 2016. The Notes will mature on April 1, 2021, unless earlier redeemed, repurchased or converted. The Notes are unsecured and are subordinated to secured debt to the extent of the value of the assets securing such indebtedness.

The Notes are convertible at the option of the holder at any time prior to the close of business on the business day immediately preceding the maturity date. The conversion rate is initially 311.4295 shares of Common Stock per $1,000 principal amount of Notes (equivalent to an initial conversion price of approximately $3.21 per share of Common Stock). The conversion rate is subject to adjustment in some events but will not be adjusted for any accrued and unpaid interest. In addition, following certain corporate events that occur prior to the maturity date, the Company will increase the conversion rate for a holder who elects to convert its Notes in connection with such a corporate event in certain circumstances.

The Company may not redeem the Notes prior to April 5, 2019, except in certain circumstances following a fundamental change (as defined in the indenture governing the Notes). The Company may redeem for all cash or any portion of the Notes, at its option, on or after April 5, 2019, if (terms below are as defined in the indenture governing the Notes):

(i) the last reported sale price of the Company's Common Stock has been at least 150% of the conversion price then in effect for at least 20 trading days (whether or not consecutive) during any 30 consecutive trading day period (including the last trading day of such period) ending on, and including, the trading day immediately preceding the date on which the Company provides notice of redemption; and

(ii) the Company has filed all reports that it is required to file with the SEC pursuant to Section 13 or 15(d) of the Exchange Act, as applicable (other than current reports on Form 8-K), during the twelve months preceding the date on which the Company provides such notice.

The redemption price will be equal to 100% of the principal amount of the Notes to be redeemed, plus accrued and unpaid interest, if any, to, but excluding, the redemption date. No sinking fund is provided for the Notes.

If the Company undergoes a fundamental change, holders may require the Company to repurchase for cash all or any portion of their Notes at a fundamental change repurchase price equal to 100% of the principal amount of the Notes to be repurchased, plus accrued and unpaid interest to, but excluding, the fundamental change repurchase date.

Net proceeds from the sale of the Notes were $109.1 million, after deducting the initial purchasers' discount and the offering expenses payable by the Company.

(b) ***Credit Facility***

At December 31, 2016, the Company had a revolving credit facility with a syndicate of lenders. On November 16, 2016, the Company entered into a Fourth Amendment (the "**Fourth Amendment**") to its credit agreement dated September 18, 2015 (the "**Credit Agreement**"). The Fourth Amendment, among other things, increased the borrowing base from $185.0 million, with $160.0 million readily available and $25.0 million subject to the consent of all lenders, to $250 million readily available. Availability under the revolving credit facility is determined by the reserves-based borrowing base determined by the lenders. The borrowing base will be re-determined semi-annually and will be re-determined no later than May 2017. The Company's revolving credit facility is secured against the assets of the Company's subsidiaries in Colombia, Canada and the United States of America (the "**Credit Facility Group**"). The credit agreement includes a letter of credit sub-limit of up to $100 million. None of the letter of credit sub-limit had been used at December 31, 2016. Borrowings under the revolving credit facility will mature on September 18, 2018. 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.

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 2.00% and 3.00% per annum, or an alternate base rate plus a margin ranging from 1.00% per annum to 2.00% per annum, in each case based on the borrowing base utilization percentage. The alternate base rate is currently the U.S. prime rate. At December 31 2016, the weighted-average interest rate on the balance outstanding on the Company's revolving credit facility was approximately 2.96%. Undrawn amounts under the revolving credit facility bear interest at 0.75% per annum, based on the average daily amount of unused commitments. A letter of credit participation fee of 0.25% per annum will accrue on the average daily amount of letter of credit exposure.

On August 23, 2016, the Company entered into a Third Amendment (the "**Third Amendment**") to the Credit Agreement to add a bridge term loan facility (the "**Bridge Loan Facility**"), pursuant to which the lenders provided $130.0 million in secured bridge loan financing to fund a portion of the purchase price of the PetroLatina acquisition. The Bridge Loan Facility had a term of 364 days, bore interest at USD LIBOR plus 6%, and had customary bridge facility repayment terms, providing for the prepayment of the Bridge Loan Facility upon the occurrence of certain events, including certain debt issuances. It was otherwise on substantially the same terms as the existing secured revolving credit facility.

On August 23, 2016, in connection with the PetroLatina acquisition, the Company drew $95.0 million on its revolving credit facility and $130.0 million on its Bridge Loan Facility. During the three months ending September 30, 2016, the Company repaid $30.0 million of the balance outstanding on its revolving credit facility.

During the three months ending December 31, 2016, upon the sale of non-core assets (Note 7), the Company repaid $5.0 million of the balance outstanding on the Bridge Loan Facility and, concurrent with the effectiveness of the Fourth Amendment, repaid the remaining balance on the Bridge Loan Facility using available borrowing capacity under its Credit Agreement. This resulted in a balance outstanding on its revolving credit facility of $190 million. The Company subsequently drew an additional $37.0 million on its revolving credit facility and repaid $137.0 million of the balance outstanding on this facility primarily using proceeds from its November 2016 equity offering (Note 9).

As part of the PetroLatina acquisition, Gran Tierra assumed PetroLatina's reserve-backed credit facility with an outstanding balance as at the PetroLatina Acquisition Date of $80.0 million. This credit facility plus accrued interest was repaid by Gran Tierra upon closing of the PetroLatina Acquisition on August 23, 2016.

(c) ***Interest expense***

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

	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2016**	**2015**	**2014**
Contractual interest and other financing expenses	**$ 8,454**	$ —	$ —
Amortization of debt issuance costs	**5,691**	—	—
	$ 14,145	$ —	$ —

The Company incurred debt issuance costs in connection with the issuance of the Notes, the Bridge Loan Facility and its revolving credit facility. As at December 31, 2016, 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.

23. Share Capital

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

As at December 31, 2016, outstanding share capital consists of 390,807,194 shares of Common Stock of the Company, 4,812,592 exchangeable shares of Gran Tierra Exchangeco Inc., (the "**Exchangeco exchangeable shares**") and 3,387,302 exchangeable shares of Gran Tierra Goldstrike Inc. (the "**Goldstrike exchangeable shares**"). The Exchangeco exchangeable shares were issued upon the acquisition of Solana. The Goldstrike exchangeable shares were issued upon the business combination between Gran Tierra Energy Inc., an Alberta corporation, and Goldstrike, Inc., which is now the Company. The redemption date for the Exchangeco exchangeable shares and the Goldstrike exchangeable shares is a date to be established by the applicable Board of Directors.

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

	Shares of Common Stock	Exchangeable Shares of Gran Tierra Exchangeco Inc.	Exchangeable Shares of Gran Tierra Goldstrike Inc.
Balance, December 31, 2015	273,442,799	4,933,177	3,638,889
Shares issued upon conversion of subscription receipts (a)	57,835,134	—	—
Shares issued upon public offering (b)	43,335,000	—	—
Shares issued for acquisition (Note 3)	13,656,719	—	—
Options exercised	2,165,370	—	—
Exchange of exchangeable shares	372,172	(120,585)	(251,587)
Balance, December 31, 2016	390,807,194	4,812,592	3,387,302

(a) ***Subscription Receipts***

On July 8, 2016, the Company issued approximately 57.8 million subscription receipts ("**Subscription Receipts**") in a private placement to eligible purchasers at a price of $3.00 per Subscription Receipt for gross proceeds of $173.5 million, or net proceeds after share issuance costs of $165.8 million. The proceeds were used to partially fund the PetroLatina acquisition. Each Subscription Receipt entitled the holder to automatically receive one common share of the Company upon closing of the PetroLatina acquisition on the satisfaction of certain conditions. Upon the closing of the PetroLatina acquisition on August 23, 2016, each Subscription Receipt was converted to one common share.

(b) ***Public Offering***

On November 29, 2016, the Company issued approximately 43.3 million shares of its common stock at a public offering price of $3.00 per share for gross proceeds of $130.0 million, or net proceeds after share issuance costs of $123.0 million (the "**Offering**"). The proceeds were used to repay borrowings outstanding under the Company's revolving credit facility.

2015 Share Repurchase Program

During 2015, the Company repurchased and canceled 4.6 million shares at an average price of $2.19 for total proceeds of $10.0 million, pursuant to the terms of a share repurchase program (the "**2015 Program**") through the facilities of the Toronto Stock Exchange, the NYSE MKT and eligible alternative trading platforms in Canada and the United States. The 2015 Program expired on July 29, 2016.

Equity Compensation Awards

In December 2015, the Company's Board of Directors approved a new equity compensation program for 2016 to realign the Company's compensation programs with its renewed short and long-term strategy. The 2016 equity compensation program reflects the Company's emphasis on pay-for-performance.

In prior years, all equity awards were subject to vesting conditions based solely on the recipient's continued employment over a specified period of time. In contrast, 80% of the equity awards granted in early 2016 consisted of Performance Stock Units ("**PSUs**") and 20% consisted of stock options. Gran Tierra's Compensation Committee and Board of Directors believed it was important to revise the Company's long-term incentive program to incorporate a new form of equity award that vests based on the achievement of certain key measures of performance. The purpose of this change was to align the Company's executives and employees to achieve the operational goals established by the Board of Directors, total shareholder return and increase the net asset value per share for stockholders. The Company's equity compensation awards outstanding as at December 31, 2016, include PSUs, deferred share units ("**DSUs**"), restricted stock units ("**RSUs**") and stock options.

In accordance with the 2007 Equity Incentive Plan, 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.

The following table provides information about PSU, DSU, RSU and stock option activity for the year ended December 31, 2016:

	PSUs	DSUs	RSUs	Stock Options	
	Number of Outstanding Share Units	**Number of Outstanding Share Units**	**Number of Outstanding Share Units**	**Number of Outstanding Options**	**Weighted Average Exercise Price $/Option**
Balance, December 31, 2015	—	—	1,015,457	12,851,557	$ 4.60
Granted	3,362,717	208,698	—	1,744,165	2.69
Exercised	—	—	(476,972)	(2,165,370)	2.47
Forfeited	—	—	(179,340)	(386,320)	(4.71)
Expired	—	—	—	(2,804,554)	(6.49)
Balance, December 31, 2016	3,362,717	208,698	359,145	9,239,478	$ 4.16
Exercisable, at December 31, 2016				5,068,834	$ 5.03
Vested, or expected to vest, at December 31, 2016, through the life of the options				9,000,561	$ 4.19

Stock-based compensation expense for the year ended December 31, 2016, was $6.3 million (December 31, 2015 - $2.7 million; December 31, 2014 - $7.7 million) and was primarily recorded in G&A expenses.

At December 31, 2016, there was $10.0 million (December 31, 2015 - $3.9 million) of unrecognized compensation cost related to unvested PSUs, RSUs and stock options which is expected to be recognized over a weighted average period of 1.8 years. The weighted-average remaining contractual term of options vested, or expected to vest, at December 31, 2016 was 3.5 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 continued employment of the grantee. The number of PSUs that vest may range from zero to 200% of the target number granted based on the Company's performance with respect to the applicable performance targets. The performance targets for the PSUs outstanding as at December 31, 2016, are 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) 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; and

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

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. PSUs in excess of the target number granted will vest and be settled if performance exceeds the targeted performance goals. The Company currently intends to settle PSUs in cash.

DSUs and RSUs

DSUs and RSUs 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. The Company's historic practice has been to settle RSUs in cash and the Company currently intends to settle the RSUs and DSUs outstanding as at December 31, 2016 in cash, and, therefore, DSUs and RSUs are accounted for as liability instruments. Once a DSU or RSU is vested, it is immediately settled. During the year ended December 31, 2016, DSUs were granted to directors and will vest 100% at such time the grantee ceases to be a member of the Board of Directors. For the year ended December 31, 2016, the Company paid $1.2 million to cash settle RSUs (2015 - $1.4 million and 2014 - $3.4 million).

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. Stock options generally vest over three years. The term of stock options granted starting in May of 2013 is five years or three months after the grantee's end of service to the Company, whichever occurs first. Stock options granted prior to May of 2013 continue to have a term of ten years or three months after the end of the grantee's service to the Company, whichever occurs first.

For the year ended December 31, 2016, 2,165,370 shares of Common Stock were issued for cash proceeds of $5.3 million upon the exercise of 2,165,370 stock options (2015 – 390,000; 2014 – 3,029,853).

At December 31, 2016, the weighted average remaining contractual term of outstanding stock options was 3.5 years and of exercisable stock options was 3.3 years.

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,		
	2016	**2015**	**2014**
Dividend yield (per share)	**Nil**	Nil	Nil
Volatility	**50% to 54%**	46% to 50%	39% to 42%
Weighted average volatility	**52%**	48%	41%
Risk-free interest rate	**0.94% to 1.78%**	1.20% to 1.68%	0.78% to 1.45%
Expected term	**4-5 years**	4-5 years	4-5 years

The weighted average grant date fair value for options granted in the year ended December 31, 2016, was $1.14 (2015 - $1.24; 2014 - $2.47). The weighted average grant date fair value for options vested in the year ended December 31, 2016, was $1.52 (2015 - $2.38; 2014 - $3.63). The total fair value of stock options vested during year ended December 31, 2016, was $2.8 million (2015 - $6.8 million; 2014 - $12.4 million).

Weighted Average Shares Outstanding

	Year Ended December 31,		
	2016	**2015**	**2014**
Weighted average number of common and exchangeable shares outstanding	**320,851,538**	285,333,869	284,715,785
Shares issuable pursuant to stock options	**—**	—	—
Shares assumed to be purchased from proceeds of stock options	**—**	—	—
Weighted average number of diluted common and exchangeable shares outstanding	**320,851,538**	285,333,869	284,715,785

For the year ended December 31, 2016, 10,662,034 options, on a weighted average basis, (2015 - 13,432,287 options; 2014 - 15,621,890 options) were excluded from the diluted loss per share calculation as the options were anti-dilutive.

24. **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)	**2016**	**2015**
Balance, beginning of year	**$ 33,224**	$ 35,812
Settlements	**(872)**	(6,317)
Liabilities associated with assets sold	**(3,257)**	—
Liability incurred	**2,606**	1,556
Liabilities assumed in acquisitions (Note 3)	**15,723**	—
Accretion	**2,789**	1,313
Revisions in estimated liability	**(6,856)**	860
Balance, end of year	**$ 43,357**	$ 33,224
Asset retirement obligation - current	**$ 5,215**	$ 2,146
Asset retirement obligation - long-term	**38,142**	31,078
Balance, end of year	**$ 43,357**	$ 33,224

For the year ended December 31, 2016, settlements included cash payments of $0.6 million with the balance in accounts payable and accrued liabilities at December 31, 2016. 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 the asset retirement obligation. At December 31, 2016, the fair value of assets that are legally restricted for purposes of settling asset retirement obligations was $12.0 million (December 31, 2015 - $2.9 million). These assets are accounted for as restricted cash on the Company's balance sheet.

25. **Taxes**

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

	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2016**	**2015**	**2014**
Loss from continuing operations before income taxes			
United States	**$ (23,986)**	$ (14,061)	$ (19,744)
Foreign	**(626,248)**	(354,027)	2,610
	(650,234)	(368,088)	(17,134
	35%	35%	35
Income tax recovery expense from continuing operations expected	**(227,582)**	(128,831)	(5,997)
Foreign currency translation adjustments	**218**	(187)	(6,520
Impact of foreign taxes[1]	**(9,799)**	(13,087)	27,910
Other local taxes	**1,998**	2,354	4,433
Stock-based compensation	**1,955**	919	2,232
Increase in valuation allowance	**47,675**	37,691	94,922
Non-deductible third party royalty in Colombia	**2,550**	3,416	9,116
Other permanent differences	**(1,684)**	(2,334)	1,119
Total income tax (recovery) expense from continuing operations	**$ (184,669)**	$ (100,059)	127,215
Current income tax expense from continuing operations			
United States	**$ 1,818**	$ 1,070	$ 1,260
Foreign	**18,304**	14,313	91,605
	20,122	15,383	92,865

Deferred income tax (recovery) expense from continuing operations			
Foreign(2)	**(204,791)**	(115,442)	34,350
Total income tax (recovery) expense from continuing operations	**$ (184,669)**	$ (100,059)	$ 127,215

(1) Impact of foreign taxes in the rate reconciliation are tax effected at the 35% statutory rate and for the years ended December 31, 2016, 2015 and 2014, included $23.3 million, $11.8 million and $28.1 million, respectively, in Colombia.

(2) The deferred tax recovery for the year ended December 31, 2016, included $201.3 million associated with the ceiling test impairment loss in Colombia.

	As at December 31,	
(Thousands of U.S. Dollars)	**2016**	**2015**
Deferred Tax Assets		
Tax benefit of operating loss carryforwards	**$ 74,604**	$ 56,015
Tax basis in excess of book basis	**187,651**	139,012
Foreign tax credits and other accruals	**48,341**	22,674
Tax benefit of capital loss carryforwards	**32,278**	30,799
Deferred tax assets before valuation allowance	**342,874**	248,500
Valuation allowance	**(341,263)**	(245,259)
	1,611	3,241
Deferred Tax Liabilities	**107,230**	34,592
Net Deferred Tax Liabilities	**$ (105,619)**	$ (31,351)

	As at December 31,	
(Thousands of U.S. Dollars)	**2016**	**2015**
Operating loss carryforwards	**$ 257,023**	$ 178,677
Capital loss carryforwards	**$ 239,095**	$ 228,144
Of the operating loss and capital loss carryforwards, losses generated by the foreign subsidiaries of the Company.	**$ 496,118**	$ 355,875

In certain jurisdictions, the operating loss carryforwards expire between 2017 and 2036, while certain other jurisdictions allow operating losses to be carried forward indefinitely. The capital losses can be carried forward indefinitely.

The valuation allowance increased by $96.0 million during the year ended December 31, 2016, which included $48.3 million of acquisition date valuation allowances for Petroamerica and PetroLatina. The change in the valuation allowance was primarily due to impairment losses recorded in Peru and Brazil and an increase in the corporate tax rate in Canada, partially offset by foreign currency translation adjustments. Also, the Company continues to incur losses in the U.S., Peru, Brazil and Canada. These losses are fully offset by a valuation allowance as their recognition does not meet the "more likely than not" threshold.

In the fourth quarter of 2016, Congressional authorities in Colombia enacted new legislation which consolidated the corporate income tax and CREE tax into a single income tax at 40% for 2017 (including a surtax of 6%), 37% for 2018 (including a surtax of 4%) and 33% for 2019 and onwards. The tax rates applied to the calculation of deferred income taxes have been adjusted to reflect these changes and resulted in a decrease of the future Colombian tax liability by approximately $4.1 million when tax effected at 40%. This legislation also introduced a new 5% dividend tax on distributions of previously taxed earnings from 2017 and onwards. Additionally, the legislation increased the corporate minimum presumptive income tax from 3% to 3.5%. This tax is imposed on a taxpayer's net equity at the prior year-end when the presumptive CIT exceeds actual taxable profits.

Undistributed earnings of foreign subsidiaries as of December 31, 2016, were considered to be permanently reinvested. A determination of the amount of unrecognized deferred tax liability on these undistributed earnings is not practicable.

Effective November 1, 2016, several of Gran Tierra's subsidiaries executed intercompany sale agreements whereby certain depreciable assets were transferred within the consolidated Gran Tierra group. The purpose of the transaction was to improve the efficiency of Gran Tierra's operating and tax structures. The restructuring resulted in a consolidation of certain assets into a single entity in Colombia, an increase in the depreciable tax basis of the assets transferred, and current income taxes payable as at December 31, 2016, as a result of the capital gains taxes incurred. GAAP prohibits the recognition of current and deferred income taxes for intra-entity transfers until an asset leaves the consolidated group, therefore, the current and deferred income tax effect of the restructuring was deferred and recognized as prepaid income taxes at December 31, 2016. Since the date of the transfer, prepaid income taxes were amortized in accordance with accounting depreciation. Including the effect of tax reorganizations completed earlier in the year, at December 31, 2016, the Company's balance sheet included $54.1 million of prepaid income taxes, $12.3 million in current prepaid taxes and $41.8 million in long-term prepaid taxes, and $37.5 million of current income taxes payable.

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

	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2016**	**2015**	**2014**
Unrecognized tax benefit relating to loss or income from continuing operations, beginning of year	**$ 2,200**	$ 3,300	$ 2,900
Increases for positions relating to prior year	**—**	—	500
Decreases for positions relating to prior year		(800)	(100)
Decreases due to lapse of statute of limitations	**(2,200)**	(300)	—
Unrecognized tax benefit relating to loss or income from continuing operations, end of year	**$ —**	$ 2,200	$ 3,300
Interest and penalties (recovery) expense on the unrecognized tax benefit included in income tax expense from continuing operations	**$ —**	$ (600)	$ 400

To the extent interest and penalties may be assessed by taxing authorities on any underpayment of income tax, such amounts have been accrued and are classified as a component of income taxes in the consolidated statement of operations. As at December 31, 2016, the amount of interest and penalties on the unrecognized tax benefit included in current income tax liabilities in the consolidated balance sheet was approximately $nil (December 31, 2015 - $1.4 million).The Company had no other material interest or penalties included in the consolidated statement of operations for the three years ended December 31, 2016, respectively.

The Company and its subsidiaries file income tax returns in U.S. federal and state jurisdictions and certain other foreign jurisdictions. The Company is potentially subject to income tax examinations for the tax years 2009 through 2016 in certain jurisdictions. The Company does not anticipate any material changes to the unrecognized tax benefit disclosed above within the next twelve months.

On December 23, 2014, the Colombian Congress passed legislation which imposes an equity tax levied on Colombian operations for 2015, 2016 and 2017. The equity tax is calculated based on a legislated measure, which is based on the Company's Colombian legal entities' balance sheet equity for tax purposes at January 1, 2015. This measure is subject to adjustment for inflation in future years. The equity tax rates for January 1, 2015, 2016 and 2017, are 1.15%, 1% and 0.4%, respectively. The legal obligation for each year's equity tax liability arises on January 1 of each year; therefore, the Company recognized the annual amount of $3.1 million and $3.8 million for the equity tax expense in the consolidated statement of operations for the years ended December 31, 2016 and 2015. These amounts were paid in May and September of each year and at December 31, 2016, accounts payable included $nil (December 31, 2015 - $nil).

26. **Accounts Payable and Accrued Liabilities**

	As at December 31,	
(Thousands of U.S. Dollars)	**2016**	**2015**
Trade	**$ 80,072**	$ 54,402
Royalties	**4,542**	2,066
Employee compensation and severance	**8,152**	8,414
Other	**14,285**	5,896
	$ 107,051	$ 70,778

27. **Commitments and Contingencies**

Purchase Obligations, Firm Agreements and Leases

As at December 31, 2016, future minimum payments under non-cancelable agreements with remaining terms in excess of one year were as follows:

	Year ending December 31						
	Total	**2017**	**2018**	**2019**	**2020**	**2021**	**Thereafter**
(Thousands of U.S. Dollars)							
Oil transportation services	$13,958	$ 3,639	$ 3,639	$ 3,639	$ 3,041	$ —	$ —
Drilling, completions and seismic	4,159	2,172	1,987	—	—	—	—
Operating leases	4,111	1,971	1,259	412	402	67	—
Software and telecommunication	35	24	11	—	—	—	—
	$22,263	$ 7,806	$ 6,896	$ 4,051	$ 3,443	$ 67	$ —

Gran Tierra leases certain office space, compressors, vehicles, equipment and housing. Total rent expense for the year ended December 31, 2016, was $3.2 million (year ended December 31, 2015 – $4.0 million; year ended December 31, 2014 - $3.2 million).

Indemnities

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

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

Letters of credit

At December 31, 2016, the Company had provided promissory notes totaling $96.8 million (December 31, 2015 - $76.5 million) as security for letters of credit relating to work commitment guarantees contained in exploration contracts and other capital or operating requirements.

Contingencies

On June 6, 2016, the Company received a positive decision from the Chamber of Commerce of Bogotá Center for Arbitration and Conciliation tribunal (the "**Tribunal**") relating to its dispute with the Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) of Colombia ("**ANH**") with respect to whether all production from the Moqueta Exploitation Area of the Chaza Block exploration and production contract ("**Chaza Contract**") was subject to an additional royalty (the "**HPR**

Royalty"). In its decision, the Tribunal found that the HPR Royalty under the Chaza Contract was only payable when the accumulated oil production from the Moqueta Exploitation Area exceeded 5.0 MMbbl. That production threshold was reached on April 30, 2015, and since that time the Company has been paying the HPR Royalty on production from the Moqueta Exploitation Area.

The ANH and Gran Tierra are engaged in ongoing discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the HPR royalty. Based on the Company's understanding of the ANH's position, the estimated compensation which would be payable if the ANH's interpretation is correct could be up to $45.9 million as at December 31, 2016. At this time no amount has been accrued in the consolidated financial statements as Gran Tierra does not consider it probable that a loss will be incurred.

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

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

Financial Instruments

At December 31, 2016, the Company's financial instruments recognized in the balance sheet consist of; cash and cash equivalents; restricted cash; accounts receivable; derivative assets and liabilities; accounts payable and accrued liabilities; long-term debt; PSU liability included in other long-term liabilities; and RSU liability included in accounts payable and accrued liabilities and other long-term liabilities.

Fair Value Measurement

The fair value of derivatives and RSU and PSU liabilities are being remeasured at the estimated fair value at the end of each reporting period.

The fair value of commodity price and foreign currency 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 fair value of the RSU liability was estimated based on quoted market prices in an active market. The fair value of the PSU liability was estimated based on quoted market prices in an active market and an option pricing model such as the Monte Carlo simulation option-pricing models.

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

The fair value of trading securities, derivative assets, and RSU and PSU liabilities at December 31, 2016, and December 31, 2015 were as follows:

	As at December 31,	
(Thousands of U.S. Dollars)	**2016**	**2015**
Foreign currency derivative asset	**$ 578**	$ —
Trading securities	—	6,250
	$ 578	$ 6,250
Commodity price derivative liability	**$ 3,824**	$ —
RSU, PSU and DSU liability	**3,907**	1,189
	$ 7,731	$ 1,189

During the year ended December 31, 2016, the Company sold the trading securities for cash proceeds of $2.3 million (year ended December 31, 2015 - nil). These cash proceeds were included in cash flows from investing activities in the Company's consolidated statements of cash flows because these securities were received in connection with the sale of the Company's Argentina business unit in 2014.

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

(Thousands of U.S. Dollars)	Year Ended December 31,		
	2016	2015	2014
Trading securities loss	**$ 3,925**	$ 1,335	$ 6,326
Commodity price derivative loss	**7,370**	—	—
Foreign currency derivatives (gain) loss	**(1,016)**	692	(1,604)
	$ 10,279	$ 2,027	$ 4,722

These losses are presented as financial instruments loss in the consolidated statements of operations and cash flows. Trading securities losses related to losses on the Madalena shares Gran Tierra received in connection with the sale of its Argentina business unit in June 2014 (Note 4). All trading securities were sold during the year ended December 31, 2016 and the trading securities loss represented a realized loss. For the years ended December 31, 2015 and 2014, the trading securities loss represented an unrealized loss.

Financial instruments not recorded at fair value include the Notes (Note 8). At December 31, 2016, the carrying amount of the Notes was $109.9 million, which represents the aggregate principal amount less unamortized debt issuance costs, and the fair value was $135.6 million. The fair value of long-term restricted cash and the revolving credit facility approximated their carrying value because interest rates are variable and reflective of market rates. The fair values of other financial instruments approximate their carrying amounts due to the short-term maturity of these instruments.

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

The fair value of the RSU liability was determined using Level 1 inputs. The fair value of the derivatives was determined using Level 2 inputs. The fair value of the PSU liability was determined using Level 3 inputs.

The Company uses available market data and valuation methodologies to estimate the fair value of debt. The fair value of debt is the estimated amount the Company would have to pay a third party to assume the debt, including a 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 Company's Notes and revolving credit facility to new issuances (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The disclosure in the paragraph above regarding the fair value of the Company's revolving credit facility was determined using an income approach using Level 3 inputs. The disclosure in the paragraph above regarding the fair value of the Notes was determined using Level 2 inputs based on the indicative pricing published by certain investment banks or trading levels of the Notes, which are not listed on any securities exchange or quoted on an inter-dealer automated quotation system. The disclosure in the paragraph above regarding the fair value of cash and restricted cash was based on Level 1 inputs.

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

Commodity Price Derivatives

The Company utilizes 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.

At December 31, 2016, the Company had outstanding commodity price derivative positions as follows:

Period and type of instrument	**Volume, bopd**	**Reference**	**Sold Put ($/bbl)**	**Purchased Put ($/bbl)**	**Sold Call ($/bbl)**	**Premiums received / (paid) ($/bbl)**
Collar: June 1, 2016 to May 31, 2017	10,000	ICE Brent	$ 35	$ 45	$ 65	$ (1.25)
Collar: June 1, 2017 to December 31, 2017	10,000	ICE Brent	$ 35	$ 45	$ 65	$ 0.475
Collar: October 1, 2016 to December 31, 2017	5,000	ICE Brent	$ 35	$ 45	$ 65	$ —

During the year ended December 31, 2016, the Company paid net premiums upon entering into commodity price derivatives of $3.5 million.

Collars are a combination of put options (floor) and sold call options (ceiling). For a collar position, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor strike price while the Company is required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling strike price. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor strike price and equal to or less than the ceiling strike price. At December 31, 2015, we did not have any open commodity price derivative positions.

Foreign Exchange Risk and Foreign Currency Derivatives

The Company utilizes foreign currency derivatives to manage the variability in cash flows associated with the Company's forecasted Colombian peso ("**COP**") denominated costs.

At December 31, 2016, the Company had outstanding foreign currency derivative positions as follows:

Period and type of instrument	**Amount hedged (Millions COP)**	**Reference**	**Purchased Call (COP)**	**Sold Put[(1)] (COP)**	**Sold Put[(1)] (COP)**
Collar: January 1, 2017 to March 31, 2017	31,597.6	COP	3,100	3,300	3,345
Collar: April 1, 2017 to May 31, 2017	22,697.2	COP	3,100	3,310	3,370
	54,294.8				

(1) The put levels noted in the table above varied based on market conditions at the inception of each foreign currency derivative contract.

At December 31, 2015, the Company did not have any open foreign currency derivative positions. The Company's cash flow is only impacted when the actual settlements under the derivative contracts result in making or receiving a payment to or from the counterparty. These cash settlements represent the cumulative gains and losses on the Company's derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled. These cash settlements were included in cash flows from operating activities in the Company's consolidated statements of cash flows.

While the use of these derivative instruments may limit or partially reduce the downside risk of adverse commodity price and foreign exchange movements, their use also may limit future income and gains from favorable commodity price and foreign exchange movements.

Unrealized foreign exchange gains and losses primarily result from fluctuation of the U.S. dollar to the Colombian peso due to Gran Tierra's current and deferred tax liabilities, which are monetary liabilities mainly denominated in the local currency of the Colombian operations. As a result, foreign exchange gains and losses must be calculated on conversion to the U.S. dollar functional currency. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $43,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar. This effect was calculated based on the Company's December 31, 2016, deferred tax balances, adjusted for the expected effect of the adoption of ASU 2016-16.

For the year ended December 31, 2016, 97% (year ended December 31, 2015 - 97%, year ended December 31, 2014 - 95%) of the Company's oil and natural gas 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. In Brazil, prices for oil are in U.S. dollars, but revenues are received in local currency translated according to current exchange rates. The majority of the Company's capital expenditures within Brazil are based on U.S. dollar prices, but are paid in local currency translated according to current exchange rates. In Peru, capital expenditures are based on U.S. dollar prices and may be paid in local currency or U.S. dollars.

Credit Risk

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of cash 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, 2016, cash and cash equivalents and restricted cash included balances in bank accounts, term deposits and certificates of deposit, placed with financial institutions with strong investment grade ratings or governments.

Most of the Company's accounts receivable relate to uncollateralized sales to customers in the oil and natural gas industry and are exposed to typical industry credit risks. The concentration of revenues in a single industry affects the Company's overall exposure to credit risk because customers may be similarly affected by changes in economic and other conditions. The Company manages this credit risk by entering into sales contracts with only credit worthy entities and reviewing its exposure to individual entities on a regular basis. For the year ended December 31, 2016, the Company had three customers which were significant to the Colombian segment, and one customer which was significant to the Brazil segment.

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.

29. **Severance Expenses**

During the years ended December 31, 2016 and 2015, the Company reduced the number of its employees and contractors. Severance expenses were recorded as incurred based on existing employee contracts, statutory requirements, completed negotiations and company policy. Severance expenses were $1.3 million, $9.0 million and $nil in the three years ended December 31, 2016. At December 31, 2015, $nil (December 31, 2014 - $1.5 million) severance expense was payable.

30. **Supplemental Cash Flow Information**

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

	Year ended December 31,		
	2016	**2015**	**2014**
Accounts receivable and other long-term assets	**$ (29)**	$ 44,365	$ (34,473)
Derivatives	**(3,546)**	—	—
Inventory	**5,510**	(1,571)	(2,891)
Other prepaids	**(615)**	152	4
Accounts payable and accrued and other long-term liabilities	**(9,691)**	(33,743)	2,988
Prepaid tax and taxes receivable and payable	**(2,966)**	(48,251)	(61,064)
Net changes in assets and liabilities from operating activities of continuing operations	**$ (11,337)**	$ (39,048)	$ (95,436)

The following table provides additional supplemental cash flow disclosures:

	Year Ended December 31,		
	2016	**2015**	**2014**
Cash paid for income taxes	**$ 64,067**	$ 39,422	$ 101,179
Cash paid for interest	**$ 5,624**	$ —	$ —
Non-cash investing activities:			
Net liabilities related to property, plant and equipment, end of year	**$ 55,181**	$ 33,923	$ 113,874
Acquisition of marketable securities as proceeds from sale of Argentina business unit (Note 4)	$ —	$ —	$ 13,912

See Note 3 in these consolidated financial statements for disclosure regarding shares issued in connection with the Company's acquisition of Petroamerica.

31. **Subsequent Event**

On February 6, 2017, Gran Tierra announced that a purchase and sale agreement (the "**Agreement**") had been executed by the Purchaser to purchase Gran Tierra's Brazil business unit through the acquisition of all of the equity interests in one of Gran Tierra's indirect subsidiaries, and the assignment of certain debt owed by the corporate entities comprising Gran Tierra's Brazil business unit to the Gran Tierra group of companies (the "**Brazil Divestiture**").

Upon completion of the Brazil Divestiture, the Purchaser will acquire all of Gran Tierra's assets and certain liabilities in Brazil, including its 100% working interest in the Tiê Field and all of Gran Tierra's interest in exploration rights and obligations held pursuant to concession agreements granted by the Agência Nacional do Petróleo, Gás Natural e Biocombustíveis of Brazil ("**ANP**").

The completion of the Brazil Divestiture is subject to the Purchaser obtaining financing, as well as customary closing conditions, including the receipt of required regulatory approval from the ANP. The consideration to be received by Gran Tierra on the completion of the Brazil Divestiture is $35 million, subject to adjustments, plus the assumption by the Purchaser of certain existing and potential liabilities of Gran Tierra's Brazil business unit. Pursuant to the Agreement, the Purchaser paid a deposit of $3.5 million on February 7, 2017, which is not refundable in the event the Purchaser is not successful in obtaining financing to complete the Brazil Divestiture.

The economic effective date of the transaction will be on or before August 1, 2017, and Gran Tierra will continue to operate its Brazil business unit until the completion of the Brazil Divestiture.

Section C: Financial Statements for the six months ended 30 June 2018 (Unaudited)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	**2017**	**2018**	**2017**
OIL AND NATURAL GAS SALES (Notes 3 and 7)	**$ 163,446**	$ 96,128	**$ 301,674**	$ 190,787
EXPENSES				
Operating	**35,059**	27,208	**61,324**	51,145
Transportation	**6,522**	6,492	**13,519**	13,434
Depletion, depreciation and accretion (Note 3)	**46,607**	31,813	**86,068**	58,689
General and administrative (Note 3)	**13,213**	9,513	**24,373**	18,225
Equity tax	**—**	—	**—**	1,224
Foreign exchange loss	**1,924**	3,897	**982**	2,050
Financial instruments loss (gain) (Note 10)	**4,768**	(1,447)	**11,714**	(6,886)
Interest expense (Note 5)	**7,375**	3,331	**12,870**	6,426
	115,468	80,807	**210,850**	144,307
LOSS ON SALE	**(292)**	(9,076)	**(292)**	(9,076)
INTEREST INCOME	**610**	245	**1,396**	653
INCOME BEFORE INCOME TAXES (Note 3)	**48,296**	6,490	**91,928**	38,057
INCOME TAX EXPENSE				
Current (Note 8)	**4,827**	1,772	**17,116**	9,189
Deferred (Note 8)	**23,169**	11,525	**36,651**	22,904
	27,996	13,297	**53,767**	32,093
NET AND COMPREHENSIVE INCOME (LOSS)	**$ 20,300**	$ (6,807)	**$ 38,161**	$ 5,964
NET INCOME (LOSS) PER SHARE				
- BASIC AND DILUTED	**$ 0.05**	$ (0.02)	**$ 0.10**	$ 0.01
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC (Note 6)	***391,054,204***	*398,585,290*	***391,173,460***	*398,795,023*
WEIGHTED AVERAGE SHARES OUTSTANDING - DILUTED (Note 6)	***427,455,092***	*398,585,290*	***427,242,014***	*398,816,091*

(See notes to the condensed consolidated financial statements)

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

	As at June 30, 2018	As at December 31, 2017
ASSETS		
Current Assets		
Cash and cash equivalents (Note 11)	$ 125,807	$ 12,326
Restricted cash and cash equivalents (Note 11)	2,836	11,787
Accounts receivable	63,030	45,353
Investment (Note 10)	32,654	25,055
Derivatives (Note 10)	930	302
Taxes receivable	62,689	40,831
Other current assets	14,423	9,591
Total Current Assets	302,369	145,245
Oil and Gas Properties (using the full cost method of accounting)		
Proved	750,948	629,081
Unproved	423,808	464,948
Total Oil and Gas Properties	1,174,756	1,094,029
Other capital assets	3,440	5,195
Total Property, Plant and Equipment (Notes 3 and 4)	1,178,196	1,099,224
Other Long-Term Assets		
Deferred tax assets	18,248	57,310
Investment (Note 10)	15,302	19,147
Other long-term assets (Note 11)	5,389	6,112
Goodwill (Note 3)	102,581	102,581
Total Other Long-Term Assets	141,520	185,150
Total Assets (Note 3)	$ 1,622,085	$ 1,429,619
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	$ 126,726	$ 125,876
Derivatives (Note 10)	27,157	21,151
Taxes payable	3,848	9,324
Asset retirement obligation	110	323
Equity compensation award liability (Note 10)	11,597	295
Total Current Liabilities	169,438	156,969
Long-Term Liabilities		
Long-term debt (Notes 5 and 10)	398,130	256,542
Deferred tax liabilities	24,528	28,417
Asset retirement obligation	35,839	31,241
Equity compensation award liability (Note 10)	9,480	11,135
Other long-term liabilities	9,381	8,980
Total Long-Term Liabilities	477,358	336,315
Contingencies (Note 9)		
Shareholders' Equity		
Common Stock (Note 6) (390,017,518 and 385,191,042 shares of Common Stock and 1,135,239 and 6,111,665 exchangeable shares, par value $0.001 per share, issued and outstanding as at June 30, 2018, and December 31, 2017, respectively)	10,295	10,295
Additional paid in capital	1,328,037	1,327,244
Deficit	(363,043)	(401,204)
Total Shareholders' Equity	975,289	936,335
Total Liabilities and Shareholders' Equity	$ 1,622,085	$ 1,429,619

(See notes to the condensed consolidated financial statements)

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

	Six Months Ended June 30, 2018	2017
Operating Activities		
Net income	**$ 38,161**	$ 5,964
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation and accretion (Note 3)	**86,068**	58,689
Deferred tax expense	**36,651**	22,904
Stock-based compensation (Note 6)	**10,202**	3,183
Amortization of debt issuance costs (Note 5)	**1,513**	1,225
Cash settlement of restricted share units	**(360)**	(501)
Unrealized foreign exchange loss	**539**	1,076
Financial instruments loss (gain) (Note 10)	**11,714**	(6,886)
Cash settlement of financial instruments (Note 10)	**(15,483)**	1,216
Cash settlement of asset retirement obligation	**(369)**	(298)
Loss on sale	**292**	9,076
Net change in assets and liabilities from operating activities (Note 11)	**(37,994)**	(28,112)
Net cash provided by operating activities	**130,934**	67,536
Investing Activities		
Additions to property, plant and equipment (Note 3)	**(157,088)**	(104,025)
Property acquisitions	**(3,100)**	(30,410)
Net proceeds from sale of Brazil business unit	**—**	34,481
Cash deposit received for letter of credit arrangements upon sale of Brazil business unit	**—**	4,700
Changes in non-cash investing working capital	**(6,142)**	(627)
Net cash used in investing activities	**(166,330)**	(95,881)
Financing Activities		
Proceeds from bank debt, net of issuance costs (Note 5)	**4,988**	98,304
Repayment of bank debt (Note 5)	**(153,000)**	(33,000)
Proceeds from exercise of stock options (Note 6)	**845**	—
Repurchase of shares of Common Stock (Note 6)	**(1,208)**	(10,000)
Proceeds from issuance of Senior Notes, net of issuance costs (Note 5)	**288,087**	—
Net cash provided by financing activities	**139,712**	55,304
Foreign exchange loss on cash, cash equivalents and restricted cash and cash equivalents	**(69)**	(1,175)
Net increase in cash, cash equivalents and restricted cash and cash equivalents	**104,247**	25,784
Cash, cash equivalents and restricted cash and cash equivalents, beginning of period (Note 11)	**26,678**	43,267
Cash, cash equivalents and restricted cash and cash equivalents, end of period (Note 11)	**$ 130,925**	$ 69,051

Supplemental cash flow disclosures (Note 11)

(See notes to the condensed consolidated financial statements)

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

	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Share Capital		
Balance, beginning of period	**$ 10,295**	$ 10,303
Repurchase of Common Stock (Note 6)	**—**	(4)
Balance, end of period	**10,295**	10,299
Additional Paid in Capital		
Balance, beginning of period	**1,327,244**	1,342,656
Exercise of stock options (Note 6)	**845**	—
Stock-based compensation (Note 6)	**1,156**	1,354
Repurchase of Common Stock (Note 6)	**(1,208)**	(9,996)
Balance, end of period	**1,328,037**	1,334,014
Deficit		
Balance, beginning of period	**(401,204)**	(493,972)
Net income	**38,161**	5,964
Cumulative adjustment for accounting change related to tax reorganizations	**—**	124,476
Balance, end of period	**(363,043)**	(363,532)
Total Shareholders' Equity	**$ 975,289**	$ 980,781

(See notes to the condensed 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 oil and natural gas exploration and production in Colombia.

2. **Significant Accounting Policies**

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

The note disclosure requirements of annual consolidated financial statements provide additional disclosures to that required for interim unaudited condensed consolidated financial statements. Accordingly, these interim unaudited condensed consolidated financial statements should be read in conjunction with the Company's consolidated financial statements as at and for the year ended December 31, 2017, included in the Company's 2017 Annual Report on Form 10-K, filed with the SEC on February 27, 2018.

The Company's significant accounting policies are described in Note 2 of the consolidated financial statements which are included in the Company's 2017 Annual Report on Form 10-K and are the same policies followed in these interim unaudited condensed consolidated financial statements, except as noted below. The Company has evaluated all subsequent events through to the date these interim unaudited condensed consolidated financial statements were issued.

Recently Adopted Accounting Pronouncements

Revenue from Contracts with Customers

The Company adopted Accounting Standard Codification ("ASC") 606 Revenue from Contracts with Customers with a date of initial application of January 1, 2018 in accordance with the modified retrospective approach without using the practical expedients. Except for providing enhanced disclosures about the Company's revenue transactions, the application of ASC 606 did not have an impact on the Company's consolidated financial position, results of operations or cash flows.

(a) *Significant Accounting Policy*

The Company's revenue relates to oil and natural gas 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 ability to establish prices or having inventory risk. If the Company acts 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 the Company from the transaction.

Tariffs, tolls and fees charged to other entities for use of pipelines owned by the Company 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.

(b) *Significant Judgments*

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

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU 2016-01, "Recognition and Measurement of Financial Assets and Financial Liabilities". ASU 2016-01 addressed certain aspects of recognition, measurement, presentation and disclosure of financial instruments. ASU 2016-01 was effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2017. The implementation of this update did not impact on the Company's consolidated financial position, results of operations or cash flows or disclosure.

In February 2018, the FASB issued ASU 2018-03, "Recognition and Measurement of Financial Assets and Financial Liabilities". ASU 2018-03 clarified certain aspects of the guidance in ASU 2016-01. ASU 2018-03 is effective for annual reporting periods beginning after December 15, 2017 and interim reporting periods within those annual reporting periods beginning after June 15, 2018. Early adoption is permitted upon adoption of ASU 2016-01. The amendments should be applied retrospectively with a cumulative-effect adjustment to the effective date of ASU 2016-01. The Company early adopted this update on January 1, 2018. The implementation of this update did not impact the Company's consolidated financial position, results of operations or cash flows or disclosure.

Recently Issued but Not Yet Adopted Accounting Pronouncements

Leases

In January 2018, the FASB issued ASU 2018-01, "Land Easement Practical Expedient for Transition to Topic 842". ASU 2018-01 provides an optional transition practical expedient that, if elected, would not require an organization to reconsider their accounting for existing or expired land easements that were not previously accounted for as leases under Topic 840. The effective date and transition requirements for the amendment is the same as the effective date and transition requirements in Update 2016-02. The Company is planning to adopt ASU 2018-01 upon transition to ASU 2016-01 "Leases".

The Company is finalizing an assessment of its contract inventory using certain practical expedients to determine which contracts meet the definition of a lease. The next steps will include classifying leases as either financing or operating, establishing interest rates and determining the value of right-of-use lease assets and lease liabilities. The Company expects to apply the guidance of ASU 2016-02 using a modified retrospective transition approach.

3. Segment and Geographic Reporting

The Company is primarily engaged in the exploration and production of oil and natural gas. Commencing 2018, the Company has one reportable segment based on geographic organization, Colombia. Prior to the sale of the Company's Brazil business unit effective June 30, 2017 and Peru business unit effective December 18, 2017, Brazil and Peru were reportable segments. The "All Other" category represents the Company's corporate activities, Mexico activities and Brazil and Peru activities until the date of sale.

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

(Thousands of U.S. Dollars)	Three Months Ended June 30, 2018 Colombia	All Other	Total
Oil and natural gas sales	**$ 163,446**	**$ —**	**$ 163,446**
Depletion, depreciation and accretion	**46,065**	**542**	**46,607**
General and administrative expenses	**7,213**	**6,000**	**13,213**
Income (loss) before income taxes	**51,029**	**(2,733)**	**48,296**
Segment capital expenditures	**83,757**	**637**	**84,394**

(Thousands of U.S. Dollars)	Three Months Ended June 30, 2017 Colombia	All Other	Total
Oil and natural gas sales	$ 91,905	$ 4,223	$ 96,128
Depletion, depreciation and accretion	30,130	1,683	31,813
General and administrative expenses	5,229	4,284	9,513
Income (loss) before income taxes	21,598	(15,108)	6,490
Segment capital expenditures	55,436	2,429	57,865

(Thousands of U.S. Dollars)	Six Months Ended June 30, 2018 Colombia	All Other	Total
Oil and natural gas sales	**$ 301,674**	**$ —**	**$ 301,674**
Depletion, depreciation and accretion	**84,564**	**1,504**	**86,068**
General and administrative expenses	**14,022**	**10,351**	**24,373**
Income (loss) before income taxes	**112,180**	**(20,252)**	**91,928**
Segment capital expenditures	**156,318**	**770**	**157,088**

(Thousands of U.S. Dollars)	Six Months Ended June 30, 2017 Colombia	All Other	Total
Oil and natural gas sales	$ 182,369	$ 8,418	$ 190,787
Depletion, depreciation and accretion	55,065	3,624	58,689
General and administrative expenses	10,061	8,164	18,225
Income (loss) before income taxes	58,742	(20,685)	38,057
Segment capital expenditures	98,276	5,749	104,025

(Thousands of U.S. Dollars)	As at June 30, 2018 Colombia	All Other	Total
Property, plant and equipment	**$ 1,176,540**	**$ 1,656**	**$ 1,178,196**
Goodwill	**102,581**	**—**	**102,581**
All other assets	**175,563**	**165,745**	**341,308**
Total Assets	**$ 1,454,684**	**$ 167,401**	**$ 1,622,085**

(Thousands of U.S. Dollars)	As at December 31, 2017 Colombia	All Other	Total
Property, plant and equipment	$ 1,096,833	$ 2,391	$ 1,099,224
Goodwill	102,581	—	102,581
All other assets	176,980	50,834	227,814
Total Assets	$ 1,376,394	$ 53,225	$ 1,429,619

4. **Property, Plant and Equipment**

(Thousands of U.S. Dollars)	As at June 30, 2018	As at December 31, 2017
Oil and natural gas properties		
Proved	**$ 3,014,725**	$ 2,810,796
Unproved	**423,808**	464,948
	3,438,533	3,275,744
Other	**19,086**	26,401
	3,457,619	3,302,145
Accumulated depletion, depreciation and impairment	**(2,279,423)**	(2,202,921)
	$ 1,178,196	$ 1,099,224

The Company used an average Brent price of $62.58 per bbl for the purposes of the June 30, 2018 ceiling test calculations (March 31, 2018 - $56.92, December 31, 2017 - $54.19).

5. **Debt and Debt Issuance Costs**

The Company's debt at June 30, 2018 and December 31, 2017 was as follows:

(Thousands of U.S. Dollars)	As at June 30, 2018	As at December 31, 2017
Senior notes	**$ 300,000**	$ —
Convertible notes	**115,000**	115,000
Revolving credit facility	**—**	148,000
Unamortized debt issuance costs	**(16,870)**	(6,458)
Long-term debt	**$ 398,130**	$ 256,542

Senior Notes

On February 15, 2018, Gran Tierra Energy International Holdings Ltd. ("GTEIH"), an indirect, wholly owned subsidiary of the Company, issued $300 million of 6.25% Senior Notes due 2025 (the "Senior Notes"). The Senior Notes are fully and unconditionally guaranteed by the Company and certain subsidiaries of the Company that guarantee its revolving credit facility. Net proceeds from the sale of the Senior Notes were $288.1 million, after deducting the initial purchasers' discounts and commission and the offering expenses payable by the Company.

The 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 Senior Notes will mature on February 15, 2025, unless earlier redeemed or repurchased.

Before February 15, 2022, GTEIH may, at its option, redeem all or a portion of the 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 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%.

Interest Expense

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(Thousands of U.S. Dollars)	2018	2017	2018	2017
Contractual interest and other financing expenses	**$ 6,532**	$ 2,711	**$ 11,357**	$ 5,201
Amortization of debt issuance costs	**843**	620	**1,513**	1,225
	$ 7,375	$ 3,331	**$ 12,870**	$ 6,426

6. **Share Capital**

On May 1, 2018, Gran Tierra Exchangeco Inc., a subsidiary of the Company, announced that it had established a redemption date of July 5, 2018 in respect of all of its outstanding exchangeable shares. Effective July 5, 2018, all remaining outstanding exchangeable shares of record on July 4, 2018 were acquired for purchase consideration of one share of Gran Tierra common stock, and on July 9, 2018, the Company retired and canceled one share of Special A Voting Stock and one share of Special B Voting Stock, which held voting rights in connection with those exchangeable shares. As a result, no shares of Special A Voting Stock and Special B Voting Stock remain outstanding.

	Shares of Common Stock	Exchangeable Shares of Gran Tierra Exchangeco Inc.	Exchangeable Shares of Gran Tierra Goldstrike Inc.
Balance, December 31, 2017	385,191,042	4,422,776	1,688,889
Options exercised	319,462	—	—
Shares repurchased and canceled	(469,412)	—	—
Exchange of exchangeable shares	4,976,426	(3,287,537)	(1,688,889)
Balance, June 30, 2018	390,017,518	1,135,239	—

On March 7, 2018, the Company announced that it intended to implement a share repurchase program (the "2018 Program") through the facilities of the Toronto Stock Exchange ("TSX") and eligible alternative trading platforms in Canada. Under the 2018 Program, the Company is able to purchase at prevailing market prices up to 19,269,732 shares of Common Stock, representing approximately 5.00% of the issued and outstanding shares of Common Stock as of March 8, 2018. Shares purchased pursuant to 2018 Program will be canceled. The 2018 Program will expire on March 11, 2019, or earlier if the 5.00% share maximum is reached.

Equity Compensation Awards

The following table provides information about performance stock units (**"PSUs"**), deferred share units (**"DSUs"**), restricted stock units (**"RSUs"**) and stock option activity for the six months ended June 30, 2018:

	PSUs	DSUs	RSUs	Stock Options	
	Number of Outstanding Share Units	Number of Outstanding Share Units	Number of Outstanding Share Units	Number of Outstanding Stock Options	Weighted Average Exercise Price/Stock Option ($)
Balance, December 31, 2017	6,131,951	455,768	122,090	8,960,692	3.65
Granted	3,544,001	131,888	—	1,996,526	2.51
Exercised	—	—	(120,268)	(319,462)	2.65
Forfeited	(213,160)	—	(1,822)	(491,475)	5.42
Expired	—	—	—	(171,854)	6.15
Balance, June 30, 2018	9,462,792	587,656	—	9,974,427	3.33

Stock-based compensation expense for the three and six months ended June 30, 2018, was $6.9 million and $10.2 million, respectively, and was primarily recorded in general and administrative (**"G&A"**) expenses (three and six months ended June 30, 2017 - $2.0 million and $3.2 million, respectively).

At June 30, 2018, there was $23.0 million (December 31, 2017 - $13.7 million) of unrecognized compensation cost related to unvested PSUs and stock options which is expected to be recognized over a weighted average period of 1.8 years.

Net Income per Share

Basic net income per share is calculated by dividing net income by the weighted average number of shares of Common Stock and exchangeable shares issued and outstanding during each period. Diluted net income per share is similarly calculated except that the common shares outstanding for the period is increased using the treasury stock method to reflect the potential dilution that could occur if outstanding stock awards were vested at the end of the applicable period plus potentially issuable shares on conversion of the convertible notes. Anti-dilutive shares represent potentially dilutive securities that are excluded from the computation of diluted income or loss per share as their impact would be anti-dilutive.

Weighted Average Shares Outstanding

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	**2017**	**2018**	**2017**
Weighted average number of common and exchangeable shares outstanding	**391,054,204**	398,585,290	**391,173,460**	398,795,023
Shares issuable pursuant to stock options	**4,894,633**	—	**2,420,509**	625,631
Shares assumed to be purchased from proceeds of stock options	**(4,308,138)**	—	**(2,166,348)**	(604,563)
Shares issuable pursuant to convertible notes	**35,814,393**	—	**35,814,393**	—
Weighted average number of diluted common and exchangeable shares outstanding	**427,455,092**	398,585,290	**427,242,014**	398,816,091

For the three months ended June 30, 2018, 5,240,018 options, on a weighted average basis, (three months ended June 30, 2017 - 10,634,157 options) were excluded from the diluted income (loss) per share calculation as the options were anti-dilutive. For the six months ended June 30, 2018, 7,385,714 options, on a weighted average basis, (six months ended June 30, 2017 - 9,616,800 options) were excluded from the diluted income per share calculation as the options were anti-dilutive. Shares issuable upon conversion of the 5.00% Convertible Notes due 2021 ("Convertible Notes") were dilutive and included in the diluted income per share calculation. For the three and six months ended June 30, 2018, the numerator used in the computation of diluted earnings per share included net income for the period adjusted for interest on convertible debentures and amortization of debt issuance costs of $1.7 million and $3.4 million, respectively.

7. **Revenue**

Most of the Company's revenues are from oil sales at prices which reflect the blended prices received upon shipment by the purchaser at defined sales points or are defined by contract relative to ICE Brent and adjusted for Vasconia crude, quality and transportation discounts each month. For the three and six months ended June 30, 2018, 100% (three and six months ended June 30, 2017 - 100%) of the Company's revenue resulted from oil sales. During the three and six months ended June 30, 2018, quality and transportation discounts were 14% and 15%, respectively, of the ICE Brent price (three and six months ended June 30, 2017 - 21% and 22%, respectively). During the three and six months ended June 30, 2018, the Company's production was sold primarily to three major customers in Colombia (three and six months ended June 30, 2017 - four).

As at June 30, 2018, accounts receivable included $4.8 million of accrued sales revenue which related to June 2018 production (December 31, 2017 - $11.1 million which related to December 31, 2017 production).

8. **Taxes**

The Company's effective tax rate was 58% in the six months ended June 30, 2018, compared with 84% in the comparative period in 2017. Current income tax expense was higher in the six months ended June 30, 2018, compared with the corresponding period in 2017, primarily as a result of higher taxable income in Colombia. The deferred income tax expense of $36.7 million for the six months ended June 30, 2018, was primarily due to excess tax depreciation compared with accounting depreciation in Colombia.

For the six months ended June 30, 2018, the difference between the effective tax rate of 58% and the 21% U.S. statutory rate was primarily due to an increase to the impact of foreign taxes, valuation allowance, stock-based compensation, foreign currency translation and non-deductible third party royalty in Colombia.

For the comparative period in 2017, the effective tax rate differed from the U.S. statutory rate of 35% primarily due to an increase in the valuation allowance, which was largely attributable to losses incurred in the United States, Brazil and Colombia, as well as the impact of a non-deductible third-party royalty in Colombia, foreign and local taxes, and stock-based compensation. These items were partially offset by foreign currency translation adjustments and other permanent differences.

9. Contingencies

The Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) ("ANH") and Gran Tierra are engaged in ongoing discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of an additional royalty (the "HPR royalty"). Based on the Company's understanding of the ANH's position, the estimated compensation which would be payable if the ANH's interpretation is correct could be up to $52.8 million as at June 30, 2018. At this time no amount has been accrued in the interim unaudited condensed consolidated financial statements as Gran Tierra does not consider it probable that a loss will be incurred.

In addition to the above, the Company has a number of other lawsuits and claims pending. Although the outcome of these other lawsuits and disputes cannot be predicted with certainty, the Company 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 associated with these lawsuits and claims as they are incurred or become probable and determinable.

Letters of credit and other credit support

At June 30, 2018, the Company had provided letters of credit and other credit support totaling $69.8 million (December 31, 2017 - $76.0 million) as security relating to work commitment guarantees contained in exploration contracts and other capital or operating requirements.

10. Financial Instruments and Fair Value Measurement

Financial Instruments

At June 30, 2018, the Company's financial instruments recognized in the balance sheet consisted of: cash and cash equivalents; restricted cash and cash equivalents; accounts receivable; investments; derivatives, accounts payable and accrued liabilities, long-term debt and equity compensation award liability.

Fair Value Measurement

The fair value of certain investments, derivatives and equity compensation awards (PSU and DSU) liabilities are remeasured at the estimated fair value at the end of each reporting period.

The fair value of the short-term portion of the Company's investment in PetroTal Corp. ("PetroTal") (formerly Sterling Resources Ltd.) was estimated using quoted prices at June 30, 2018 and the foreign exchange rate at that time. The fair value of the long-term portion of the investment restricted by escrow conditions was estimated using observable and unobservable inputs; factors that were evaluated included quoted market prices, precedent comparable transactions, risk-free rate, measures of market risk volatility, estimates of the Company's and PetroTal's costs of capital and quotes from third parties.

The fair value of commodity price and foreign currency 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 fair value of the PSU liability was estimated based on option pricing model using inputs such as quoted market prices in an active market, and PSU performance factors. The fair value of the DSU liabilities was estimated based on quoted market prices in an active market.

The fair value of the Company's investment in PetroTal, derivatives and PSU and DSU liabilities at June 30, 2018, and December 31, 2017, was as follows:

(Thousands of U.S. Dollars)	As at June 30, 2018		As at December 31, 2017	
Investment in PetroTal shares - current and long-term	**$**	**47,956**	$	44,202
Foreign currency derivative asset		**930**		302
	$	**48,886**	$	44,504
Commodity price derivative liability	**$**	**27,157**	$	21,151
Equity compensation award liability - current and long-term		**21,077**		11,430
	$	**48,234**	$	32,581

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

	Three Months Ended June 30,				Six Months Ended June 30,			
(Thousands of U.S. Dollars)	2018		2017		2018		2017	
Commodity price derivative loss (gain)	**$**	**14,461**	$	(1,545)	**$**	**19,455**	$	(6,247)
Foreign currency derivatives loss (gain)		**1,945**		98		**(2,024)**		(639)
Investment gain		**(11,638)**		—		**(5,717)**		—
Financial instruments loss (gain)	**$**	**4,768**	$	(1,447)	**$**	**11,714**	$	(6,886)

Investment gain for the three and six months ended June 30, 2018, related to the fair value gain on the PetroTal shares Gran Tierra received or subscribed for in connection with the sale of its Peru business unit in December 2017. For the three and six months ended June 30, 2018, this investment gain was unrealized.

Financial instruments not recorded at fair value include the Senior Notes and the Convertible Notes. At June 30, 2018, the carrying amounts of the Senior Notes and the Convertible Notes were $288.6 million and $111.5 million, respectively, which represented the aggregate principal amount less unamortized debt issuance costs, and the fair values were $282.0 million and $143.8 million, respectively. The fair value of long-term restricted cash and cash equivalents and the revolving credit facility approximated their carrying value because interest rates are variable and reflective of market rates. The fair values of other financial instruments approximate their carrying amounts due to the short-term maturity of these instruments.

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

At June 30, 2018, the fair value of the current portion of the investment and DSU liability was determined using Level 1 inputs, the fair value of derivatives and PSUs was determined using Level 2 inputs and the fair value of the long-term portion of the investment restricted by escrow conditions was determined using Level 3 inputs. The table below presents the fair value of the long-term portion of the investment:

(Thousands of U.S. Dollars)	Six Months Ended June 30, 2018		Year Ended December 31, 2017	
Opening balance, investment - long-term	**$**	**19,147**	$	—
Acquisition		**—**		19,091
Transfer from long-term (Level 3) to current (Level 1)		**(4,787)**		—
Unrealized valuation gain		**2,528**		**56**
Unrealized foreign exchange loss		**(1,586)**		—
Closing balance, investment - long-term	**$**	**15,302**	$	19,147

The Company uses available market data and valuation methodologies to estimate the fair value of debt. The fair value of debt is the estimated amount the Company would have to pay a third party to assume the debt, including a 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 Company's Senior Notes, Convertible Notes and revolving credit facility to new issuances (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The disclosure above regarding the fair value of the Convertible Notes was determined using Level 2 inputs based on the indicative pricing published by certain third-party services or trading levels of the Convertible Notes, which are not listed on any securities exchange or quoted on an inter-dealer automated quotation system. The disclosure in the paragraph above regarding the fair value of cash and restricted cash and cash equivalents, revolving credit facility and Senior Notes was based on Level 1 inputs.

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

Commodity Price Derivatives

The Company utilizes 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.

At June 30, 2018, the Company had outstanding commodity price derivative positions as follows:

Period and type of instrument	Volume, bopd	Reference	Sold Swap ($/bbl, Weighted Average)	Purchased Call ($/bbl, Weighted Average)
Swaps: July 1, to December 31, 2018	5,000	ICE Brent	$ 55.90	n/a
Participating Swaps: July 1, to December 31, 2018	5,000	ICE Brent	$ 52.50	$ 56.11

The Company does not have any outstanding commodity price derivative positions relating to 2019.

Foreign Currency Derivatives

The Company utilizes foreign currency derivatives to manage the variability in cash flows associated with the Company's forecasted Colombian peso ("COP") denominated expenses. At June 30, 2018, the Company had outstanding foreign currency derivative positions as follows:

Foreign Currency Derivatives

The Company utilizes foreign currency derivatives to manage the variability in cash flows associated with the Company's forecasted Colombian peso ("COP") denominated expenses. At June 30, 2018, the Company had outstanding foreign currency derivative positions as follows:

Period and type of instrument	Amount Hedged (Millions COP)	U.S. Dollar Equivalent of Amount Hedged (Thousands of U.S. Dollars)[1]	Reference	Purchased Call (COP)	Sold Put (COP, Weighted Average)
Collars: July 1, 2018 to December 31, 2018	87,000	29,685	COP	3,000	3,107

(1) At June 30, 2018 foreign exchange rate.

11. Supplemental Cash Flow Information

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

(Thousands of U.S. Dollars)	As at June 30,		As at December 31,	
	2018	2017	2017	2016
Cash and cash equivalents	**$ 125,807**	$ 53,310	$ 12,326	$ 25,175
Restricted cash and cash equivalents - current	**2,836**	5,844	11,787	8,322
Restricted cash and cash equivalents - long-term (included in other long-term assets)	**2,282**	9,897	2,565	9,770
	$ 130,925	$ 69,051	$ 26,678	$ 43,267

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

(Thousands of U.S. Dollars)	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Accounts receivable and other long-term assets	**$ (11,723)**	$ 11,024
Derivatives	**3,431**	—
Inventory	**(3,054)**	(47)
Prepaids	**(301)**	2,190
Accounts payable and accrued and other long-term liabilities	**971**	(6,179)
Taxes receivable and payable	**(27,318)**	(35,100)
Net changes in assets and liabilities from operating activities	**$ (37,994)**	$ (28,112)

The following table provides additional supplemental cash flow disclosures:

(Thousands of U.S. Dollars)	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Non-cash investing activities:		
Net liabilities related to property, plant and equipment, end of period	**$ 62,009**	$ 56,044

APPENDIX 2 – COMPETENT PERSON'S REPORT

GRAN TIERRA ENERGY INC.

Competent Person's Report
Colombia Assets
As of July 31, 2018

McDaniel & Associates Consultants Ltd.

GRAN TIERRA ENERGY INC.

Competent Person's Report
Colombia Assets
As of July 31, 2018

Prepared For:

Gran Tierra Energy Inc.
900, 520 – 3rd Avenue SW
Calgary, Alberta
T2P 0R3

Prepared By:

McDaniel & Associates Consultants Ltd.
2200, 255 - 5th Avenue SW
Calgary, Alberta
T2P 3G6

September 2018

GRAN TIERRA ENERGY INC.

Competent Person's Report
Colombia Assets

Table of Contents

TABLES

FIGURES

September 28, 2018

Gran Tierra Energy Inc.
900, 520 – 3rd Avenue SW
Calgary, Alberta
T2P 0R3

Reference: **Gran Tierra Energy Inc.**
Competent Person's Report as of July 31, 2018
Colombia Assets

Attention: Mr. Alan Johnson, Vice President, Asset Management

Dear Sir:

1 INTRODUCTION

Pursuant to your request, we have prepared an evaluation of the crude oil and natural gas reserves and the net present value of these reserves for the interests of Gran Tierra Energy Inc. (the "Company" or "Gran Tierra") in 20 fields in Colombia as of July 31, 2018.

The future net revenues and net present values presented in this report were calculated using forecast prices and costs using McDaniel & Associates Consultants Ltd. ("McDaniel") opinion of future crude oil prices at July 1, 2018 and were presented in United States dollars ("USD"). The reserves and resource estimates and future net revenue forecasts have been prepared in accordance with standards set out in the Canadian National Instrument 51-101 ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook ("COGEH").

This evaluation was prepared during the period from June 2018 to August 2018 and was based on technical and financial data to the end of July 2018. Gran Tierra has provided McDaniel with written representation that all technical, financial and ownership information relevant to our opinion has been provided and that no new data or information has been acquired up to the date of this report which might materially impact our opinions in this report. All the basic information employed in the preparation of this report was obtained from Gran Tierra.

The Company has provided McDaniel with a signed representation letter indicating that there are no matters which have arisen since the effective date of the Reserves Report which would require a change to the Reserves Report in order to make the Reserves Report accurate and not misleading, and we are not aware of any matter in relation to the Reserves Report that we believe should be, and has not yet been, bought to the attention of the Company.

2 CORPORATE SUMMARY

Gran Tierra has an interest in 30 blocks (the "Blocks") in Colombia in the Middle Magdalena Valley ("MMV"), Putumayo, Llanos and Sinu basins, of which 13 contain producing fields. A general location map of the basins within Colombia is shown in Figure 1, and maps outlining the locations of the Putumayo Basin and MMV Basin blocks can be found in Figure 2 and Figure 3 respectively.

Figure 1 - Property Location Map

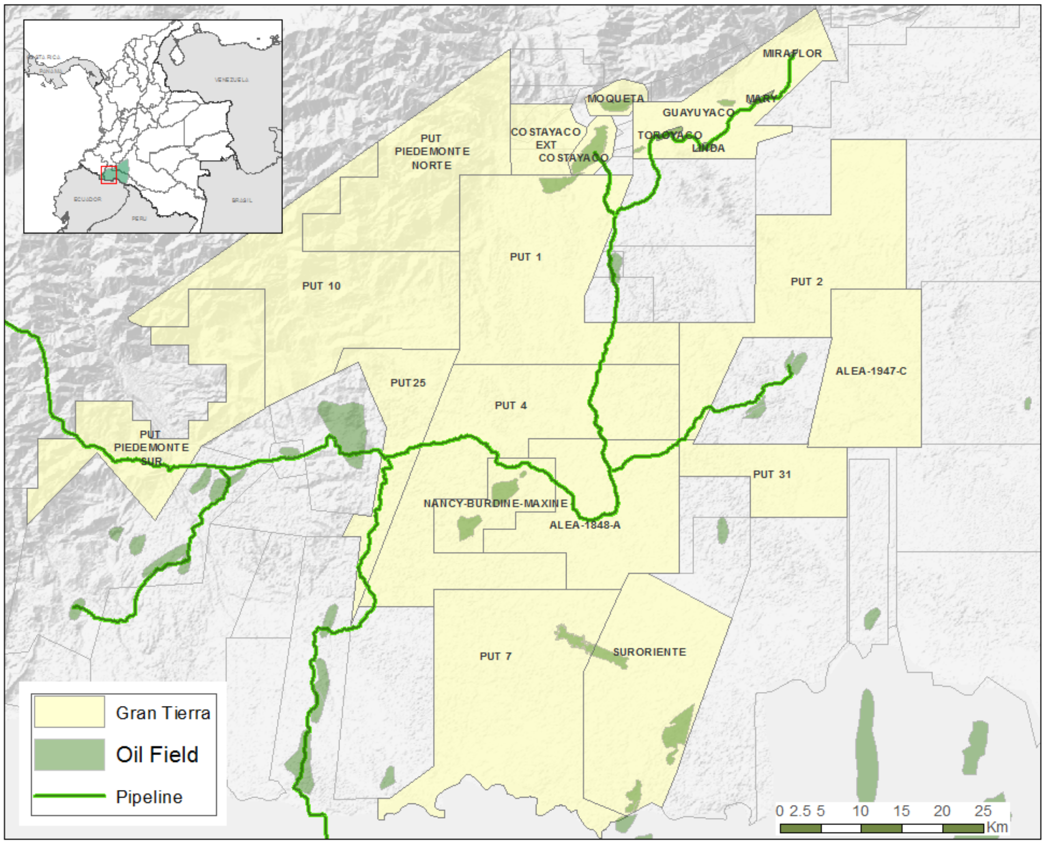


Figure 2 – Putumayo Basin Blocks Location Map

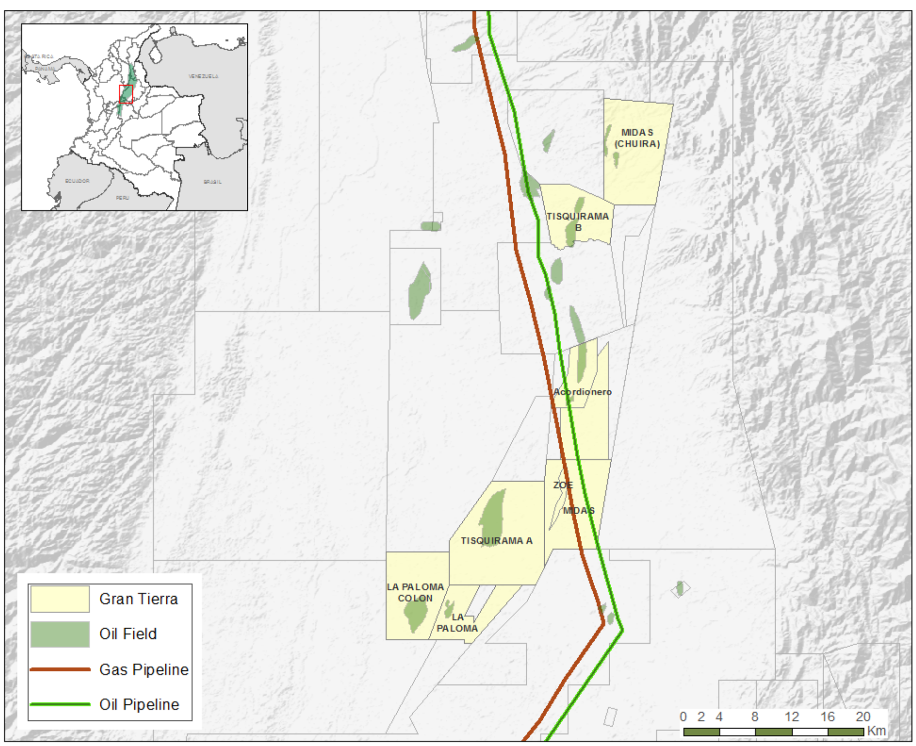


Figure 3 – Middle Magdalena Valley Basin Blocks Location Map

A summary of Gran Tierra's interest in the producing Blocks and exploration Blocks is presented in Table 1 and Table 2 respectively.

Basin	Block[(1)]	Producing Fields	Operated	Working Interest	Partners	Gross Acres	End of Exploitation Phase
Putumayo	Chaza	Costayaco, Moqueta, Guriyaco	Yes	100%	N/A	16,472	2033 (Costayaco & Guriyaco) 2037 (Moqueta)
Putumayo	Guayuyaco	Guayuyaco, Juanambu	Yes	70%	Ecopetrol	52,366	2030
Putumayo	NBM	Nancy	Yes	100%	N/A	26,187	Until economic limit
Putumayo	PUT-1	Vonu	Yes	55%	Lewis Energy	114,881	24 years from commerciality
Putumayo	PUT-7	Cumplidor, Confianza	Yes	100%	N/A	130,186	24 years from commerciality
Putumayo	Santana	Mary, Miraflo Toroyaco	Yes	100%	N/A	1,119	Until economic limit
Putumayo	Suroriente	Cohembi, Quinde	No	15.8%[(2)]	Vetra, Ecopetrol	90,264	2024
Llanos	Garibay	Jilguero	No	30-50%[(3)]	Cepsa	1,903	2037
Llanos	LLA-22	Ramiriqui	No	45%	Cepsa	25,018	2038
MMV	La Paloma	Colon, Juglar	Yes	100%	N/A	23,756	2034 (Colon) 2039 (Juglar)
MMV	Midas	Acordionero, Chuira, Zoe	Yes	100%	N/A	26,108	2039 (Acordionero) 2035 (Chuira)
MMV	Tisquirama B	Los Angeles, Querubin	Yes	20-40%[(4)]	Ecopetrol	10,719	Until economic limit
MMV	VMM-2	Mono Arana	Yes	60%	Canacol	4,200	2039

(1) Only includes fields that have been assigned crude oil or natural gas reserves in this report
(2) Gran Tierra holds a 15.8 percent revenue interest and 30.45 percent cost interest in the Suroriente Block.
(3) The Mirador Reservoir in the Jilguero Field is part of a unitization agreement whereby Gran Tierra receives a 30.35 percent working interest. The other reservoirs in the Jilguero Field and the Melero Field are not part of the unitization agreement and, therefore, Gran Tierra holds a 50 percent working interest.
(4) Gran Tierra holds a 40 percent interest revenue interest and 50 percent cost interest in the Los Angeles Field and a 20 percent revenue interest and 25 percent cost interest in the Querubin Field.

Table 1 - Gran Tierra Producing Blocks Summary

Basin	Block	Operated	Working Interest	Partners	Gross Acres	Remaining Commitments, Current Phase	End of Current Phase(1)
Putumayo	Alea 1848-A	Yes	100%	N/A	75,764	70 km 2D seismic, 1 exploration well	2018
Putumayo	Alea 1947-C	Yes	100%	N/A	58,068	1 exploration well	Suspended(2)
Putumayo	PPN	Yes	70%	Cepsa	78,742	52 km 2D seismic	Suspended(2)
Putumayo	PPS	Yes	100%	N/A	73,898	2 km 2D seismic, 1 exploration well	Suspended(2)
Putumayo	PUT-1	Yes	55%	Lewis Energy	114,881	2 exploration wells	2020
Putumayo	PUT-2	Yes	100%	N/A	96,666	3 exploration wells	2019
Putumayo	PUT-4	Yes	100%	N/A	126,848	1 exploration well	2019
Putumayo	PUT-7	Yes	100%	N/A	130,186	1 exploration well	2018
Putumayo	PUT-10	Yes	100%	N/A	114,097	73 km 2D seismic, 2 exploration wells	Suspended(2)
Putumayo	PUT-25	Yes	100%	N/A	41,015	N/A	2018
Putumayo	PUT-31	Yes	100%	N/A	34,826	N/A	2018
Llanos	El Porton	Yes	100%	N/A	109,476	1 exploration well	Suspended(2)
Llanos	LLA-1	Yes	100%	N/A	133,954	97.5 km^2 3D seismic, 1 exploration well	Suspended(2)
Llanos	LLA-10	No	50%	Parex	189,536	1 exploration well	Suspended(2)
Llanos	LLA-22	No	45%	Cepsa	25,018	85 km^2 3D seismic, 1 exploration well	Suspended(2)
Llanos	LLA-53	Yes	100%	N/A	67,456	89 km^2 3D seismic, 2 exploration wells	Suspended(2)
Llanos	LLA-70	Yes	100%	N/A	109,519	163 km^2 3D seismic, 1 exploration well	Suspended(2)
Caguan-Putumayo	Tinigua	Yes	40%	Frontera	105,466	1 exploration well	Suspended(2)
Sinú	SN-1	Yes	60%	Perenco	503,000	1 stratigraphic well (pending approval to convert to exploration well)	2018

Basin	Block	Operated	Working Interest	Partners	Gross Acres	Remaining Commitments, Current Phase	End of Current Phase(1)
Sinú	SN-3	Yes	51%	Pluspetrol	483,000	N/A	2018

(1) Dates are subject to extension based on progress of activities and other factors, such as delays in local consultations.
(2) Gran Tierra's obligation to carry out the exploration activities on these blocks is currently suspended indefinitely due to licensing restrictions or security issues.

Table 2 – Gran Tierra Exploration Blocks Summary

2.1 Reserves

Crude oil and natural gas reserves have been assigned to the 20 producing fields in Colombia. The property gross and Gran Tierra's gross and net working interest share of the crude oil and natural gas reserves as of July 31, 2018 are presented in Table 3 below:

Crude Oil Reserves at July 31, 2018, Mbbl

	Proved Producing	Proved Developed Non-Producing	Proved Developed	Proved Undeveloped	Total Proved	Probable	Total Proved & Probable	Possible	Total Proved, Probable & Possible
Light and Medium Oil (Mbbl)									
Gross	29,182	5,545	34,727	8,185	42,912	28,687	71,600	41,140	112,740
Net	23,299	4,424	27,723	6,545	34,267	22,886	57,153	31,348	88,501
Heavy Oil (Mbbl)									
Gross	13,969	51	14,020	12,987	27,008	37,914	64,922	31,337	96,258
Net	11,528	37	11,565	10,749	22,314	30,253	52,567	23,573	76,140
Natural Gas (MMcf)									
Gross	1,474	0	1,474	792	2,266	1,303	3,569	1,656	5,225
Net	1,380	0	1,380	741	2,121	1,220	3,341	1,550	4,891
Total (MBOE)									
Gross (1)	43,397	5,596	48,993	21,304	70,297	66,819	137,116	72,753	209,869
Net (2)	35,057	4,461	39,518	17,417	56,935	53,342	110,277	55,179	165,456

(1) Company gross reserves are based on Gran Tierra's working interest reserves before deductions of royalties payable to others.
(2) Net reserves are based on Company share of reserves after royalties and NPI.

Table 3 - Gran Tierra Reserves Summary

2.2 Net Present Values of the Reserves

The net present values of the crude oil reserves were based on future production and revenue analyses. Gran Tierra's share of the net present values of the reserves, based on forecast prices and costs as of July 31, 2018, are presented in Tables 4 and 5 below:

Before Tax Net Present Values at July 31, 2018, US$MM (1) (2)

	Discounted At				
	0%	5%	10%	15%	20%
Proved Producing Reserves	1,270.9	1,154.3	1,059.0	979.9	913.5
Proved Developed Non-Producing Reserves	145.9	122.5	104.9	91.3	80.6
Proved Developed Reserves	1,416.8	1,276.9	1,163.9	1,071.3	994.2
Proved Undeveloped Reserves	493.9	394.6	318.8	260.0	213.5
Total Proved Reserves	1,910.8	1,671.5	1,482.7	1,331.3	1,207.7
Probable Reserves	2,243.4	1,634.1	1,238.4	969.4	779.2
Proved + Probable Reserves	4,154.1	3,305.6	2,721.2	2,300.6	1,986.9
Possible Reserves	2,288.0	1,620.3	1,198.7	920.3	728.8
Proved + Probable + Possible Reserves	6,442.1	4,925.8	3,919.8	3,220.9	2,715.7

(1) Based on forecast prices and costs at July 1, 2018 (see Table 9).
(2) The net present values may not necessarily represent the fair market value of the reserves.

Table 4 - Gran Tierra Before Tax Net Present Value Summary of the Reserves

After Tax Net Present Values at July 31, 2018, US$MM (1) (2)

	Discounted At				
	0%	5%	10%	15%	20%
Proved Producing Reserves	1,086.0	985.2	902.1	832.8	774.3
Proved Developed Non-Producing Reserves	101.2	85.3	73.2	63.8	56.3
Proved Developed Reserves	1,187.3	1,070.5	975.3	896.6	830.7
Proved Undeveloped Reserves	336.2	256.4	198.8	154.0	118.6
Total Proved Reserves	1,523.5	1,326.9	1,174.0	1,050.5	949.3
Probable Reserves	1,539.8	1,118.4	842.3	654.1	521.0
Proved + Probable Reserves	3,063.2	2,445.3	2,016.3	1,704.7	1,470.3
Possible Reserves	1,517.6	1,092.5	812.2	623.2	491.8
Proved + Probable + Possible Reserves	4,580.8	3,537.8	2,828.5	2,327.9	1,962.1

(1) Based on forecast prices and costs at July 1, 2018.
(2) The net present values may not necessarily represent the fair market value of the reserves.

Table 5 - Gran Tierra After Tax Net Present Value Summary of the Reserves

2.3 Crude Oil Prospective Resources

Crude oil and natural gas prospective resources were assigned to several prospects and leads within the Putumayo, Llanos and Sinu basins and are summarized in Table 6 on a Company gross basis below and a Property gross basis in Table 7.

	Gran Tierra Working Interest Prospective Resources Unrisked (1)				Risked Resources pre-COD (2)	Risked Resources post COD
	Low	**Median**	**Mean**	**High**	**Mean**	**Mean**
Basin	Mbbl/MMcf	Mbbl/MMcf	Mbbl/MMcf	Mbbl/MMcf	Mbbl/MMcf	Mbbl/MMcf
Crude Oil						
Putumayo Basin – A Limestone	225,883	684,883	822,443	1,602,415	269,239	214,313
Putumayo Basin – N Sand	32,979	95,921	134,460	281,232	67,270	59,465
Putumayo Basin – Structural	40,499	107,844	149,760	313,381	32,901	24,962
Llanos Basin	38,331	89,804	116,748	226,018	19,846	15,767
Sinu Basin	6,407	33,212	64,777	165,234	7,286	4,355
Middle Magdalena Valley Basin	38,885	94,556	114,524	214,011	47,666	41,320
Total (3)(4)(5)	**382,983**	**1,106,221**	**1,402,712**	**2,802,290**	**444,207**	**360,183**
Natural Gas						
Putumayo Basin – A Limestone	-	-	-	-		
Putumayo Basin – N Sand	-	-	-	-	-	-
Putumayo Basin – Structural	-	-	-	-	-	-
Llanos Basin	-	-	-	-	-	-
Sinu Basin	10,376	50,708	96,158	242,538	10,831	6,465
Middle Magdalena Valley Basin	372	753	859	1,486	330	99
Total (3)(4)(5)	**10,748**	**51,461**	**97,017**	**244,024**	**11,161**	**6,564**
BOE (6)						
Putumayo Basin – A Limestone	225,883	684,883	822,443	1,602,415	269,239	214,313
Putumayo Basin – N Sand	32,979	95,921	134,460	281,232	67,270	59,465
Putumayo Basin – Structural	40,499	107,844	149,760	313,381	32,901	24,962
Llanos Basin	38,331	89,804	116,748	226,018	19,846	15,767
Sinu Basin	8,136	41,663	80,803	205,657	9,091	5,432
Middle Magdalena Valley Basin	38,947	94,682	114,667	214,258	47,721	41,337
Total (3)(4)(5)	**384,775**	**1,114,797**	**1,418,881**	**2,842,961**	**446,067**	**361,277**

(1) There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.
(2) The risked resources have been risked for chance of discovery and chance of development (COD). The chance of development is defined as the probability of a project being commercially viable. Quantifying the chance of development requires consideration of both economic contingencies and other contingencies, such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are extremely difficult to quantify, the chance of development is uncertain and must be used with caution.
(3) Sub-Total and Total are based on the probabilistic aggregation of zones within a prospect and arithmetic aggregation of the individual prospects to the Sub-Total and Total level.
(4) The Unrisked Total is not representative of the Portfolio Unrisked Total and is provided to give an indication of the resources range assuming all of the prospects are successful.
(5) Volumes listed are full life volumes, prior to any cutoffs due to economics.
(6) Based on a Mcf to BOE conversion of 6 to 1.

Table 6 - Gran Tierra Prospective Resources Summary

	Property Gross Prospective Resources Unrisked (1)				Risked Resources pre-COD (2)	Risked Resources post COD
	Low	Median	Mean	High	Mean	Mean
Basin	Mbbl/MMcf	Mbbl/MMcf	Mbbl/MMcf	Mbbl/MMcf	Mbbl/MMcf	Mbbl/MMcf
Crude Oil						
Putumayo Basin – A Limestone	295,085	893,402	1,072,044	2,087,194	346,769	270,594
Putumayo Basin – N Sand	34,485	102,270	143,996	303,833	71,755	62,852
Putumayo Basin – Structural	55,170	140,644	189,985	388,248	42,087	37,155
Llanos Basin	67,875	155,730	199,053	381,147	42,219	33,666
Sinu Basin	10,678	55,353	107,962	275,390	12,143	7,258
Middle Magdalena Valley Basin	40,460	98,232	118,804	221,723	49,518	42,773
Total (3)(4)(5)	**503,752**	**1,445,631**	**1,831,843**	**3,657,535**	**564,491**	**454,298**
Natural Gas						
Putumayo Basin – A Limestone	-	-	-	-		
Putumayo Basin – N Sand	-	-	-	-	-	-
Putumayo Basin – Structural	-	-	-	-	-	-
Llanos Basin	-	-	-	-	-	-
Sinu Basin	17,294	84,514	160,263	404,230	18,051	10,775
Middle Magdalena Valley Basin	929	1,883	2,148	3,714	825	247
Total (3)(4)(5)	**18,223**	**86,397**	**162,410**	**407,945**	**18,876**	**11,022**
BOE (6)						
Putumayo Basin – A Limestone	295,085	893,402	1,072,044	2,087,194	346,769	270,594
Putumayo Basin – N Sand	34,485	102,270	143,996	303,833	71,755	62,852
Putumayo Basin – Structural	55,170	140,644	189,985	388,248	42,087	37,155
Llanos Basin	67,875	155,730	199,053	381,147	42,219	33,666
Sinu Basin	13,560	69,439	134,672	342,761	15,152	9,054
Middle Magdalena Valley Basin	40,615	98,545	119,162	222,343	49,655	42,814
Total (3)(4)(5)	**506,789**	**1,460,030**	**1,858,912**	**3,725,525**	**567,637**	**456,135**

(1) There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.
(2) The risked resources have been risked for chance of discovery and chance of development (COD). The chance of development is defined as the probability of a project being commercially viable. Quantifying the chance of development requires consideration of both economic contingencies and other contingencies, such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are extremely difficult to quantify, the chance of development is uncertain and must be used with caution.
(3) Sub-Total and Total are based on the probabilistic aggregation of zones within a prospect and arithmetic aggregation of the individual prospects to the Sub-Total and Total level.
(4) The Unrisked Total is not representative of the Portfolio Unrisked Total and is provided to give an indication of the resources range assuming all of the prospects are successful.
(5) Volumes listed are full life volumes, prior to any cutoffs due to economics.
(6) Based on a Mcf to BOE conversion of 6 to 1.

Table 7 – Property Gross Prospective Resources Summary

2.4 Reserves Reconciliation

The company gross crude oil reserves reconciliation between the previous evaluation, dated effective December 31, 2018 and this CPR effective July 31, 2018 is presented in Table 8 below.

Total (Mboe)	1P	2P	3P
December 31, 2017	74,124	136,994	202,518
Production	(7,735)	(7,735)	(7,735)
Exploration Discoveries	686	2,112	4,056
Drilling Extensions / Infill Drilling	2,555	1,068	2,028
Improved Recovery	-	-	-
Discoveries	-	-	-
Acquisitions	1,103	3,777	8,705
Dispositions	-	-	-
Other	-	-	-
Economic Factors	-	-	-
Technical Revisions	(435)	901	296
July 31, 2018	70,297	137,116	209,869

Table 8 – Company Gross Reserves Reconciliation

3 RESERVES AND RESOURCES DEFINITIONS

The crude oil reserves and the crude oil and natural gas contingent resources estimates presented in this report were based on the Canadian reserves definitions and guidelines prepared by the Standing Committee on Reserves Definitions of the CIM (Petroleum Society) as presented in the COGE Handbook. A summary of those definitions is presented below.

3.1 Reserves

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical and engineering date; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified according to the level of certainty associated with the estimates and may be sub-classified based on development and production status.

3.2 Development and Production Status

Each of the reserves categories (proved, probable and possible) may be divided into developed and undeveloped categories:

- **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
- **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
- **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
- **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable, possible) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

3.3 Reserves Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates

- **Proved Reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
- **Probable Reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved + probable reserves.

- **Possible Reserves** are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved + probable + possible reserves.

Other criteria that must also be met for the classification of reserves are provided in the COGE Handbook.

3.4 Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest-level sum of individual entity estimates for which reserves estimates are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved + probable reserves; and
- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved + probable + possible reserves.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

3.5 Project Maturity Sub-Classes

The use of project maturity sub-classes is relevant for all resource classes and is recommended, within the COGE Handbook, for best practice. The boundaries between the maturity sub-classes represent "decision gates" that reflect the actions (business decisions) required by the resource owner to move the project up the maturity "ladder" towards commercial production. The figure presented below, displays the COGE Handbook sub-classes with respect to the SPE-PRMS resources classification framework.

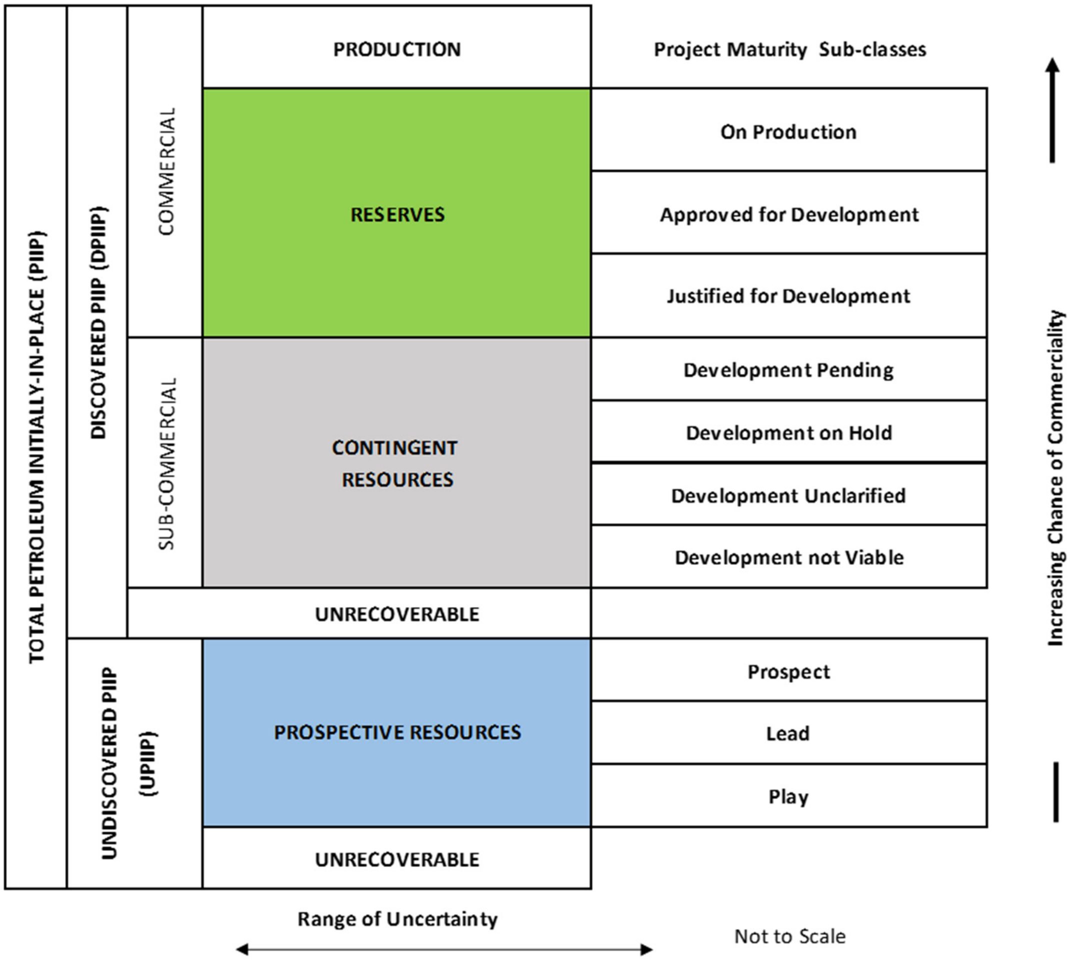


Figure 4 - Reserves Sub-classes based on Project Maturity

3.6 Resources Other Than Reserves

The estimation and classification of resources other than reserves is detailed in Section 2 of COGE Volume 2. A summary of the definitions pertaining to contingent resources and prospective resources are presented below.

3.7 Contingent Resources

Contingent resources are defined as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

3.8 Prospective Resources

Prospective resources are defined as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

3.9 Resource Uncertainty Categories

Estimates of resources always involve uncertainty, and the degree of uncertainty can vary widely between accumulations/projects and over the life of a project. Consequently, estimates of resources should generally be quoted as a range according to the level of confidence associated with the estimates. An understanding of statistical concepts and terminology is essential to understanding the confidence associated with resources definitions and categories.

The range of uncertainty of estimated recoverable volumes may be represented by either deterministic scenarios or a probability distribution. Resources should be provided as low, best and high estimates, as follows:

- **Low Estimate –** This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P_{90}) that the quantities actually recovered will equal or exceed the low estimate.
- **Best Estimate –** This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P_{50}) that the quantities actually recovered will equal or exceed the best estimate.
- **High Estimate –** This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P_{10}) that the quantities actually recovered will equal or exceed the high estimate.

3.10 Contingent Resources Categories

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. No specific terms are defined for incremental quantities within Contingent Resources.

3.11 Prospective Resources Categories

For Prospective Resources, the general cumulative terms low/best/high estimates apply. No specific terms are defined for incremental quantities within Prospective Resources.

4 SOURCE AND QUALITY OF DATA

Essentially all of the basic information employed in the preparation of this report was obtained from Gran Tierra's Calgary office. A workshop was setup by Gran Tierra, which provided detailed information on the geological, geophysical and engineering aspects of each field.

Digital logging data and deviation surveys were provided for all wells. Petrophysical interpretations, mud log data, completion and test data, final well reports and workover reports were available for all wells. Core analysis and reservoir fluid studies, where available, were provided. Seismic interpretation of surfaces and faults for the key horizons were provided in digital format and the actual seismic project was available for review on a workstation setup by Gran Tierra.

McDaniel has conducted numerous trips to Gran Tierra's offices in Bogota, Colombia for technical meetings with the local staff as well as a review of available core samples. The last trip conducted was in October 2017.

It is our opinion that the data available for this evaluation was of good quality and sufficient to prepare reasonable estimates of the reserves for properties evaluated in this Competent Person's Report ("CPR").

5 REGIONAL GEOLOGY

As previously mentioned, the Blocks assigned reserves are located in the Putumayo, Llanos, and MMV basins, while the Blocks assigned resources are located in the Putumayo, Llanos, MMV, and Sinu basins. A regional description of each basin is provided below.

5.1 Putumayo Basin

The Putumayo Basin is the northernmost part of a large foreland Putumayo-Oriente-Marañon Basin which straddles from Colombia through Ecuador to Peru. The names of the individual parts of the whole geological Putumayo Basin change based on the political borders and as such the Putumayo Basin is referred only to the part situated in Colombia. From the west and northwest, the Putumayo Basin is bounded by the Eastern Cordillera foothills thrust belt and the Garzon Massif. Through the adjacent Caguan Basin the Putumayo Basin is separated to the north from the Llanos Basin by the Macarena Uplift and limited to the east by the Guyana Shield. Towards the south, the Putumayo Basin becomes the Oriente Basin without any identified geological boundary.

The tectonic evolution of the Putumayo Basin is closely related to the number of compressional events, of which the most recent and most influential was the Cenozoic Andean Orogeny, considered to have produced the major Andes uplift. It forced metamorphic and igneous rocks of the eastern mountain range to thrust over the Tertiary and Cretaceous foreland section creating an extremely complex structure of the foothills area and causing compressional folding over the Putumayo Basin.

The stratigraphic section of the Putumayo Basin starts with the Precambrian metamorphic and igneous basement overlain by the volcanoclastic rocks of the Jurassic Saldaña (Motema) Formation, which is widely considered in the area as an economic basement. The actual Putumayo Basin's sedimentary fill is comprised of Cretaceous rocks of the Caballos and Villeta formations and Tertiary rocks of Rumiyaco, Pepino, Orteguaza, Orito-Belén, and Caiman formations capped by Quaternary sediments.

The organic rich carbonates and shales of the Villeta Formation are widely recognized as the main source rock in the Putumayo Basin. The Villeta Formation reaches significant thickness exceeding 1,000 feet. The oil migration is believed to be mainly vertical through faulting but also lateral along the stratigraphic units.

The primary productive reservoirs within the Putumayo Basin are sands of the Lower Cretaceous Caballos Formation and the T and U sandstone units of the Villeta Formation of the Cretaceous Albian and Cenomanian age respectively. There are a number of oil fields where these reservoirs are being developed in the Putumayo Basin such as Costayaco, Moqueta, and Orito. The Upper Cretaceous
N Sand is another major production reservoir which is being developed in the Cohembi, Quinde and Cumplidor fields and also actively explored in the southern Putumayo Basin. In 2016, the A Limestone which is one of the carbonate members of the Upper Cretaceous Villeta Formation was re-entered in the Costayaco Field and tested behind-the-pipe oil at commercial rates. Subsequently, the A Limestone emerged as a major exploration target in the western and central parts of the Putumayo Basin.

The Caballos sand unconformably overlies the Saldaña/Basement and is interpreted to be deposited in a near shore deltaic to estuarian, tide influenced environment. It displays good reservoir qualities and reaches approximately 300 feet in some areas but is generally 100 to 200 feet thick. Sealing is provided by the Caballos shale. The fluvial Albian T Sand of the Villeta Formation marks the beginning of the transgressive cycle. The sand is overlain by a tight B Limestone, which provides an excellent seal. The U Sand shows a very similar setting, marking the beginning of another transgressive cycle within the Villeta Formation. Unlike the Caballos Sand, the T and U sands are characterized by a wide distribution within the Putumayo Basin and can have abrupt changes in thickness and reservoir quality. The Turonian A Limestone is widespread throughout the Putumayo Basin and in the western part (outer platform-like fairway) reaches a thickness of approximately 100 feet. The A Limestone has been typically found to be tight, but its reservoir properties can be greatly enhanced with vugs and fractures. The Maastrichtian N Sand is situated at the top of the Cretaceous section sandwiched between a thick shale sequence at the top of the Villeta and massive shale section of the Paleogene Rumiyaco Formation. The N Sand was deposited as a northwest to southeast trending fairway in the middle part of the Putumayo Basin. It is typically found on downthrown fault blocks or as part of an erosional feature and appears to be interpretable through seismic amplitude analysis on good quality seismic. The N Sand thickness is normally 10 to 30 feet and can be highly variable.

5.2 Llanos Basin

The Llanos Basin is one of the most prolific oil-bearing basins in Colombia. It is located along the western margin of the Guyana Shield and covers more than 200,000 square kilometres ("km^2"). The Llanos Basin is bounded by Eastern cordillera to the west, by Guyana Shield to the east, by Arauca structural arch to the north and by Vaupes structural arch to the south.

The oldest sedimentary rocks penetrated in the area belong to Paleozoic age. The most important stage in the Llanos Basin development started during Triassic-Jurassic time when syn-rift was developed between the current sub-Andean zone and Eastern Cordillera. This extensional episode was related to the separation of North and South America. During Cretaceous time, thick sedimentary marine rocks were deposited, including the excellent source rock, Gacheta Formation. During Tertiary time, the area underwent a change in the tectonic regime and structural configuration due to the Andean uplift. Excellent reservoirs in the Mirador Formation were also formed during this time. The deposition of fluvio-deltaic sequences occurred until Early Miocene time and during Late Miocene time Monterralo movements (part of the Andean orogeny) began resulting in the forming of thrusts and extensive folding. Several movements were interpreted during the Miocene time and they formed the present-day structural configuration of the area. During Eocene time, the Llanos Basin and nearby foothills were affected by some erosional events due to tectonic movements of the Andes and part of sedimentary layers were eroded.

The structural configuration of the Llanos Basin can be divided into two parts – eastern and western. The eastern part of the Llanos Basin has gentle structural configurations with anticline structures complicated by low displacement faults. The western part displays more active tectonics with thrusts and number of faults developed here. The main structures in the western part are faulted blocks with high angle horizons and faulted anticlines with partial rollovers.

The main potential reservoirs in the basin are located within the Mirador, Une, Guadalupe, Barco and Carbonera formations.

5.3 Sinu Basin

The Sinu Basin is located in the northwestern part of Colombia and it is a part of the larger Sinu – San Jasinto Basin. The Basin is separated from the Lower Magdalena Basin on the east by the Romeral fault system. On the west, the Sinu Basin transforms into the Sinu Marino (off-shore) Basin. The northern and southern boundaries of the basin are related to the major fault systems. The boundary between the Sinu and San Jasinto basins relates to the Sinu fault system.

The dominant structures of the Sinu Basin were produced by westward-vergent thrust faults. Numerous mud volcanos are surface expressions of over pressured shales, which migrate upward along both thrust and strike-slip faults. Thrust faults are expressed on the surface by steep-sided, asymmetrical anticlines, which are separated by broad synclines filled with clastics shed during Tertiary thrusting. The extremely thick section of Tertiary sediments is dominated by shale but contains some potential reservoir sandstones.

The sedimentary fill of the Sinu Basin consists of Cretaceous, Paleogene and Neogene predominantly clastic sediments. The Cretaceous and Paleogene rocks are outcropping in the eastern part of Sinu and San-Jasinto basins. The total thickness of sedimentary rocks exceeds 8,000 metres.

Reservoir rocks are expected to be present in the Lower Miocene, Oligocene, Eocene and Paleocene. Stacked reservoir sandstones are possible in these intervals and confirmed in outcrops on the edge of the basin. Two major mature source rock intervals are expected to be present in the area based on the regional data, including the Cretaceous Cansona Formation and Eocene Toluviejo Formation. The working hydrocarbon system in the area is confirmed by the presence of shallow oil fields and oil seeps. A number of shale intervals could provide a seal for potential reservoirs.

5.4 Middle Magdalena Valley Basin

The MMV Basin is one of the main oil and gas producing basins in Colombia, which accounts for approximately 15 percent of current oil and gas production in the country. According to published information, there are 41 oil and gas fields with total reserves of 1.9 Bbbl and 2.5 Tcf of gas discovered in the MMV Basin.

The MMV Basin is located along the central part the Magdalena River Valley between Eastern and Central Cordilleras of the Colombian Andes. The eastern and western basin boundaries are related to blocks of pre-Cretaceous rocks of Cordilleras and is bounded to the north and south by major fault systems. The MMV Basin is only approximately 80 kilometres wide but extends from south to north by approximately 450 kilometres.

The MMV Basin sedimentary fill consists of Jurassic-Lower Cretaceous (Berriasian) fluvial clastic and volcanic rocks, Lower Cretaceous calcareous and silica-clastic shallow marine depositions, Albian-Maastrichtian shallow to deep marine strata (Simiti and La Luna formations) and Upper Cretaceous–Paleocene shallow marine to non-marine siliciclastic rocks (Umir and Lisama formations). The upper section consists of Cenozoic fluvial and lacustrine rocks deposited during the growing Eastern and Central Cordilleras.

The evolution of the MMV Basin is determined by the eastward advance of the Andian orogenesis. During the Jurassic period, Pangea began to pull apart causing separation of North America from South America. This rifting produced a subduction zone where the Nazca plate was subducting to the east under the South American plate. Part of this subducting plate was the Baudo-Island Arc separated from the South American continent by the marginal Colombian Sea. The formation of the extensional Back-Arc Basin associated with this subduction is the origin of the Middle Magdalena Basin in the late Jurassic. Throughout the Cretaceous, the MMV Basin experienced thermal subsidence.

In the Paleocene, the rate of subduction increased causing the marginal Colombian Sea to close and the Baudo-Island Arc to collide with the South American continent. This caused accretion of the Western Cordillera and uplift of the Central Cordillera transforming the back-arc basin into the pre-Andean foreland basin. Around the time of the Oligocene, the Nazca plate increased its subduction to the east while the South American plate experienced a westward pull. This caused the Andean orogeny in the Miocene and uplift of the Eastern Cordillera in the Pliocene.

The MMV Basin succession consists of an eastward-thickening wedge with 2 to 10 kilometres of Mesozoic–Cenozoic strata deposited on Proterozoic to Lower Paleozoic basement. Along the western margin, a regional angular unconformity was identified. This event is related to late Paleocene–Early Eocene erosion. A number of smaller unconformities were also identified in the area and are related to minor uplifts and local growth of the structural highs.

As for the structural setting the MMV Basin is intermontane hinterland basin largely controlled by west directed thrusting along the west edge of Eastern cordillera. The structures in Cretaceous and younger rocks are often compressed and broken by north to south oriented faults.

Cretaceous limestones and shales of the La Luna and Simiti Tablazo formations are considered main source rocks in the MMV Basin. The total organic carbon ("TOC") is between one and six percent and the organic matter is reported to be mainly Type II with Ro values from 0.6 to 1.2. The major phase of hydrocarbon generation began approximately five million years ago in Neogene and continue up to present day.

Most of the hydrocarbon accumulations in the basin were discovered in non-marine Paleogene sandstones of the Lisama, Esmeraldas-La Paz and Colorado–Mugrosa formations.

6 PRICE FORECASTS

The net present value estimates were based on McDaniel's opinion of future crude oil prices at July 1, 2018. A summary of the reference crude oil price forecasts are presented in Table 9 below:

Year	WTI Crude Oil Price $US/bbl	Brent Crude Oil Price $US/bbl	Inflation Forecast %
2018 (6 mos)	69.00	75.00	2.00
2019	65.30	69.40	2.00
2020	66.60	69.70	2.00
2021	69.00	71.10	2.00
2022	73.10	75.30	2.00
2023	74.50	76.70	2.00
2024	76.00	78.30	2.00
2025	77.50	79.80	2.00
2026	79.10	81.40	2.00
2027	80.70	83.10	2.00
2028	82.30	84.70	2.00
2029	83.90	86.40	2.00
2030	85.60	88.10	2.00
2031	87.30	89.90	2.00
2032	89.10	91.70	2.00
Thereafter	+2%/yr	+2%/yr	2.00

Table 9 – Crude Oil Price Forecasts

7 GENERAL COLOMBIAN FISCAL REGIME

Oil production from Agencia Nacional de Hidrocarburos ("ANH") contracts in Colombia is subject to a state royalty regime, as well as normal corporate income taxes. The royalty regime consists of a base royalty, which is on a sliding scale based on production from the field, as well as an additional high price royalty ("HPR") that escalates with oil prices, applicable once certain production thresholds have been met (five million barrels produced from the field or the block, depending on the contract). Details of these royalties and income taxes are summarized in the tables below.

State Oil Royalty (field)							8 percent
			Prod	<	5000 bopd		8 percent
	5000 bopd	<	Prod	<	125,000 bopd		8-20 percent lin
	125,000 bopd	<	Prod	<	400,000 bopd		20 percent
	400,000 bopd	<	Prod	<	600,000 bopd		20-25 percent
	600,000 bopd	<					25 percent
			Oil	<	15API	75% of above rates	
State Gas Royalty							80 percent of

High Price Fee (Oil)

Fee = Associate production * Q factor

Q factor = WTI price - Base Pric * S Payment Percentage
WTI Price

Applies when

Field cumulative production (net of royalty) exceeds 5,000 Mbbl
and WTI exceeds Base price

Base price (escalated annually with US PPI)

10	<	Oil API	<	15	54.12 $ US
15	<	Oil API	<	22	37.89 $ US
22	<	Oil API	<	29	36.54 $ US
29	<	Oil API			35.16 $ US

S Payment Percentge, % 30 percent

Table 10 - General Colombian Fiscal Regime

The Nancy-Burdine-Maxine (for existing production) and Santana blocks are not subject to the sliding scale royalty; they are subject to royalties of 20 percent and 32 percent, respectively. The Acordionero, Costayaco and Moqueta fields are currently subject to the HPR. Blocks with additional royalties are summarized in Table 11 below:

Basin	Block	Producing Fields	Royalty	Payable To
Putumayo	Chaza	Costayaco, Moqueta, Guriyaco	5% NPI(1)	3rd party
Putumayo	PUT-2	N/A	1%	ANH
Putumayo	PUT-4	N/A	1%	ANH
Putumayo	PUT-7	Cumplidor, Confianza	1% 10%	ANH 3rd party
Putumayo	PUT-25	N/A	19%	ANH
Putumayo	PUT-31	N/A	12%	ANH
Llanos	LLA-1	N/A	31%	ANH
Llanos	LLA-10	N/A	3%	ANH
Llanos	LLA-22	Ramiriqui	1%	ANH
Llanos	LLA-53	N/A	33%	ANH
Llanos	LLA-70	N/A	31%	ANH

(1) Net Profit Interest (NPI) is applied after deducting state royalties and operating costs.

Table11 – Blocks Subject to Additional Royalties

8 ACORDIONERO FIELD

8.1 Property Overview

The Acordionero Field is part of the Midas Contract located in the Middle Magdalena Valley Basin in western-central Colombia. The Acordionero Field is situated on land in relatively flat terrain. The facilities at Acordionero are conventional in nature. There are no material environmental concerns regarding the field's operation or its eventual abandonment. The Acordionero Field is located within 10 kilometres of the town of San Martín in the César region of Colombia and is easily accessible by road, with power, water and other services and equipment available as needed. Gran Tierra operates the fields in accordance with normal international oilfield practices for occupational health and safety, including ISO 14001 certification.

The Acordionero Field was discovered in 2013 with the drilling of the ACD-1 well. Since that time two wells were drilled in 2014, one in 2015 and two in 2016. In 2017, 12 producing wells and two water injection wells were drilled in the field, and in the first half of 2018 Gran Tierra drilled an additional three producing wells. Production commenced in July 2013 and the cumulative production from the field was 12.2 MMbbl as of July 31, 2018.

In 2017, Gran Tierra commenced waterflooding and brought its 15,000 bwpd injection facility on line. The Company has successfully injected water in the Lisama A and C in two injector wells. Going forward, Gran Tierra plans to drill an additional 12 development wells and five injection wells in the Acordionero Field and is expanding its central processing facility to increase water injection capacity up to 40,000 bwpd, fluid handling capacity up to 45,000 bfpd and truck loading capacity up to 30,000 bopd in 2018 to 2019. The crude oil produced from the Acordionero Field is delivered via truck to Puerto Bahia.

8.2 Geology

The Acordionero Field is located in the central eastern part of the MMV Basin and is a southern extension of the San Roque Field, which is a mature producing field. The structure is interpreted to be a compressed anticline with the west side of the anticline having a very steep dip and a rollover to a fault on the east; however, there is still structural uncertainty in the area along the main fault due to poor seismic imaging. There are two main oil-bearing reservoirs in the field referred to as the Lisama A Sand and Lisama C Sand. A smaller oil accumulation also exists in the Lisama D Sand and Gran Tierra is also currently exploring deeper intervals below the Lisama D Sand.

8.3 Crude Oil Reserves Estimates

The crude oil reserves were based on volumetric, reservoir simulation and performance derived estimates considering all available data including production data, test data, structural and net pay interpretations, reservoir and fluid characteristics, performance of analogous reservoirs and economics of development. A summary of the total economic Acordionero Field reserves by reserves category are presented in Table 12 below.

Crude Oil Reserves at July 31, 2018, Mbbl

	Proved Producing	Proved Developed Non-Producing	Proved Developed	Proved Undeveloped	Total Proved	Probable	Total Proved & Probable	Possible	Total Proved, Probable & Possible
Light and Medium Oil (Mbbl)									
Gross	8,333.5	469.6	8,803.1	1,473.4	10,276.5	7,613.1	17,889.6	10,509.0	28,398.6
Net	6,823.6	362.0	7,185.6	1,242.4	8,437.5	6,136.4	14,573.9	8,321.1	22,895.0
Heavy Oil (Mbbl)									
Gross	11,843.1	-	11,843.1	11,090.2	22,933.4	31,196.5	54,129.9	23,208.9	77,338.8
Net	9,695.0	-	9,695.0	9,141.3	18,826.9	25,091.9	43,918.8	18,187.1	62,105.9
Total (MBOE)									
Gross (1)	20,176.6	469.6	20,646.2	12,563.6	33,209.9	38,809.6	72,019.5	33,718.0	105,737.5
Net (2)	16,518.6	362.1	16,880.7	10,383.7	27,264.4	31,228.3	58,492.7	26,508.2	85,000.9

(1) Company gross reserves are based on Gran Tierra's working interest reserves before deductions of royalties payable to others.
(2) Net reserves are based on Company share of reserves after royalties and NPI.

Table 12 – Acordionero Field Reserves Summary

8.4 Production Forecasts and Development Plans

Gran Tierra is planning significant development in the Acordionero Field over the next several years which includes drilling Lisama A and Lisama C production wells, dual and some zone dedicated injection wells and upgrading facilities to handle additional oil production and to implement a water injection scheme.

The total proved ("1P") forecast is based on drilling seven producing wells and increasing the overall field production to approximately 20,000 bopd. The total proved + probable ("2P") forecast is based on drilling another two producing wells in 2018/2019 to increase production rates up to over 24,000 bopd. The total proved + probable + possible ("3P") forecast is based on three more production wells than the 2P case and increasing production rates up to over 27,000 bopd.

8.5 Net Present Value Estimates

The net present values of the crude oil reserves were based on future production and revenue analyses. All of the revenues and costs presented in this report were presented in USD.

The future crude oil revenue was derived by employing the future production forecast for each reserves category and the McDaniel July 1, 2018 forecast of future crude oil prices. McDaniel reviewed the percentage of production sold to various delivery points and the actual prices received for six months of 2018 as well as information provided by Gran Tierra on expected prices and delivery routes for the remainder of 2018 and going forward.

Government share of revenues is through a sliding scale royalty and HPR. Gran Tierra has indicated that the sliding scale royalties are paid separately for the Lisama A and Lisama C Sand production, while the cumulative production for determining the HPR is determined on a field basis. Operating costs were based on a combination of the 2018 accounting and our experience of analogous oil projects. Capital costs were based on the 2018/2019 budget provided by Gran Tierra. An allowance was made for well abandonment costs at the end of each respective forecast.

A summary of the before tax and after tax net present value estimates are presented in Table 13 and Table 14 below respectively.

Before Tax Net Present Values at July 31, 2018, US$MM (1) (2)					
	Discounted At				
	0%	5%	10%	15%	20%
Proved Producing Reserves	710.9	641.2	584.8	538.4	499.7
Proved Developed Non-Producing Reserves	11.4	8.6	6.6	5.1	4.0
Proved Developed Reserves	722.3	649.8	591.4	543.5	503.8
Proved Undeveloped Reserves	386.9	317.0	264.1	223.1	190.9
Total Proved Reserves	1,109.2	966.8	855.5	766.7	694.6
Probable Reserves	1,470.2	1,039.2	769.7	592.3	470.2
Proved + Probable Reserves	2,579.4	2,006.0	1,625.2	1,359.0	1,164.8
Possible Reserves	1,360.8	889.2	625.9	466.6	363.5
Proved + Probable + Possible Reserves	3,940.2	2,895.2	2,251.1	1,825.6	1,528.3

(1) Based on forecast prices and costs at July 1, 2018 (see Table 9).
(2) The net present values may not necessarily represent the fair market value of the reserves.

Table 13 – Acordionero Field Before Tax Net Present Value Summary of the Reserves

After Tax Net Present Values at July 31, 2018, US$MM (1) (2)					
	Discounted At				
	0%	5%	10%	15%	20%
Proved Producing Reserves	635.2	571.9	520.3	477.8	442.1
Proved Developed Non-Producing Reserves	7.7	5.8	4.5	3.5	2.8
Proved Developed Reserves	642.8	577.7	524.8	481.3	444.9
Proved Undeveloped Reserves	259.8	209.1	170.8	141.1	117.7
Total Proved Reserves	902.7	786.8	695.6	622.4	562.6
Probable Reserves	992.7	700.3	517.1	396.3	313.1
Proved + Probable Reserves	1,895.4	1,487.1	1,212.7	1,018.7	875.8
Possible Reserves	916.9	598.4	420.3	312.5	242.7
Proved + Probable + Possible Reserves	2,812.2	2,085.5	1,633.0	1,331.2	1,118.4

(1) Based on forecast prices and costs at July 1, 2018.
(2) The net present values may not necessarily represent the fair market value of the reserves.

Table 14 – Acordionero Field After Tax Net Present Value Summary of the Reserves

9 COSTAYACO FIELD

9.1 Property Overview

The Costayaco Field is located in the Chaza Block in the Putumayo Basin in southwest Colombia. The Chaza Block covers approximately 189 km^2 which also includes the Guriyaco and Moqueta fields. The original Chaza Exploration and Exploitation Contract (the "Chaza Contract") with ANH was signed on June 27, 2005 and Gran Tierra entered the Chaza Block in 2006. The Field is situated on land in relatively flat terrain. The facilities at Costayaco are conventional in nature. There are no material environmental concerns regarding the field's operation or its eventual abandonment. The Costayaco Field is located within 10 kilometres of the town of Villagarzón in Colombia and is easily accessible by road, with power, water and other services and equipment available as needed. Gran Tierra operates the fields in accordance with normal international oilfield practices for occupational health and safety, including ISO 14001 certification.

The Costayaco Field was discovered in 2007 with the drilling of the C-1 well. The production phase of the field expires in 2033. Gran Tierra is the operator of the Chaza Block and holds a 100 percent working interest.

Thirty wells have been drilled in the Costayaco Field to date; the first in 2007, 25 from 2008 to 2015, two in 2016, two in 2017, and three in 2018. A majority of the wells drilled targeted the Caballos and T sands with secondary targets in the A Limestone, Lower U Sand and Kg Sand. Production commenced in July 2007 and the cumulative production from the field was 53 MMbbl as of July 31, 2018. A water injection project was implemented in the T Sand in October 2010 and in the Caballos in October 2011. The current water injection rates are approximately 46,000 bwpd, which is approximately split between the T Sand and Caballos. The production rates in June 2018 were approximately 8,600 bopd. Gran Tierra is planning to drill three new wells in the Costayaco Field in 2019

All of the required facilities are currently in place and the oil produced from the Costayaco Field is delivered via truck and pipeline to a number of delivery points including the Oleoducto Transandino ("OTA") pipeline, Ecuador's OCP pipeline and others.

9.2 Geology

The Costayaco Field is located in the northwestern part of the Putumayo Basin and positioned in the transition zone between the foreland and foothills. The Costayaco structure is an asymmetric northeast to southwest elongated anticline situated on the hanging wall of a high angle reverse Cafelina/Tucan fault system. The faults show significant rock displacement of up to 1,000 feet and essentially bound the field to the east. The western and southwestern flanks of the Costayaco structure display a gentle monocline dip ranging from one to five degrees. To the north, the Costayaco Field is bounded by a low displacement fault, which marks the change from a regional structural setting to the foothills and a close proximity to the thrust sheets of the eastern mountain range. There are five productive zones. The major reservoirs are the Caballos and T Sand of the

Villeta Formation, the emerging reservoir is the A Limestone and the secondary targets are the U Sand and Kg Sand.

9.3 Crude Oil Reserves Estimates

The crude oil reserves were based on volumetric, reservoir simulation and performance derived estimates considering all available data including production data, test data, structural and net pay interpretations, reservoir and fluid characteristics, performance of analogous reservoirs and economics of development. A summary of the total economic Costayaco Field reserves by reserves category are presented in Table 15 below.

Crude Oil Reserves at July 31, 2018, Mbbl

	Proved Producing	Proved Developed Non-Producing	Proved Developed	Proved Undeveloped	Total Proved	Probable	Total Proved & Probable	Possible	Total Proved, Probable & Possible
Light and Medium Oil (Mbbl)									
Gross	10,941.8	770.8	11,712.6	1,946.1	13,658.8	7,365.0	21,023.8	10,586.1	31,609.9
Net	8,260.9	577.4	8,838.3	1,453.2	10,291.6	5,455.0	15,746.6	7,768.3	23,514.9
Total (MBOE)									
Gross (1)	10,941.8	770.8	11,712.6	1,946.1	13,658.8	7,365.0	21,023.8	10,586.1	31,609.9
Net (2)	8,260.9	577.4	8,838.3	1,453.2	10,291.6	5,455.0	15,746.6	7,768.3	23,514.9

(1) Company gross reserves are based on Gran Tierra's working interest reserves before deductions of royalties payable to others.
(2) Net reserves are based on Company share of reserves after royalties and NPI.

Table 15 – Costayaco Field Reserves Summary

9.4 Production Forecasts and Development Plans

All of the facilities have been constructed in the Costayaco Field. Gran Tierra plans to drill two additional infill wells in 2019. A number of wells in the field have experienced water breakthrough with defined water-cut trends and accordingly oil production rates are heavily dependent on the overall fluid rates. Production rates in June 2018 were approximately 8,600 bopd.

9.5 Net Present Value Estimates

The net present values of the crude oil reserves were based on future production and revenue analyses. All of the revenues and costs presented in this report were presented in USD.

The future crude oil revenue was derived by employing the future production forecast for each reserves category and the McDaniel July 1, 2018 forecast of future crude oil prices. McDaniel reviewed the percentage of production sold to various delivery points and the actual prices received for six months of 2018 as well as information provided by Gran Tierra on expected prices and delivery routes for the remainder of 2018 and going forward.

Government share of revenues is through a sliding scale royalty and HPR, as well as an NPI of 10 percent. Operating costs were based on a combination of the 2018 accounting and our experience of analogous oil projects. Capital costs were based on the 2018/2019 budget provided by Gran Tierra. An allowance was made for well abandonment costs at the end of each respective forecast.

A summary of the before tax and after tax net present value estimates are presented in Table 16 and Table 17 below respectively.

Before Tax Net Present Values at July 31, 2018, US$MM (1) (2)

	Discounted At				
	0%	5%	10%	15%	20%
Proved Producing Reserves	267.9	247.0	229.4	214.4	201.6
Proved Developed Non-Producing	21.3	19.6	18.2	16.9	15.9
Proved Developed Reserves	289.3	266.6	247.5	231.4	217.5
Proved Undeveloped Reserves	11.5	7.7	4.5	2.0	-0.1
Total Proved Reserves	300.8	274.3	252.1	233.3	217.4
Probable Reserves	184.1	150.0	124.2	104.4	89.0
Proved + Probable Reserves	484.9	424.3	376.3	337.8	306.4
Possible Reserves	95.5	142.8	139.9	124.3	107.4
Proved + Probable + Possible	580.4	567.1	516.2	462.1	413.8

(1) Based on forecast prices and costs at July 1, 2018 (see Table 9).
(2) The net present values may not necessarily represent the fair market value of the reserves.

Table 16 – Costayaco Field Before Tax Net Present Value Summary of the Reserves

After Tax Net Present Values at July 31, 2018, US$MM (1) (2)

	Discounted At				
	0%	5%	10%	15%	20%
Proved Producing Reserves	204.1	187.8	174.0	162.3	152.2
Proved Developed Non-Producing	13.8	12.7	11.8	11.0	10.3
Proved Developed Reserves	218.0	200.5	185.8	173.2	162.4
Proved Undeveloped Reserves	5.3	1.5	-1.5	-3.8	-5.7
Total Proved Reserves	223.2	202.0	184.3	169.4	156.8
Probable Reserves	119.2	96.1	78.8	65.5	55.2
Proved + Probable Reserves	342.4	298.2	263.1	234.9	211.9
Possible Reserves	-6.3	64.9	78.4	74.4	66.1
Proved + Probable + Possible Reserves	336.1	363.0	341.5	309.3	278.0

(1) Based on forecast prices and costs at July 1, 2018.
(2) The net present values may not necessarily represent the fair market value of the reserves.

Table 17 – Costayaco Field After Tax Net Present Value Summary of the Reserves

10 MOQUETA FIELD

10.1 Property Overview

The Moqueta Field is located in the Chaza Block in the Putumayo Basin in southwest Colombia. The Chaza Block covers approximately 189 km^2 which also includes the Costayaco and Guriyaco fields. The original Chaza Exploration and Exploitation Contract (the "Chaza Contract") with the ANH was signed on June 27, 2005 and Gran Tierra entered the Chaza Block in 2006.

The Moqueta Field was discovered in 2010 with the drilling of the M-1 well and the production phase expires in 2037. Gran Tierra is the operator of the Chaza Block and holds a 100 percent working interest. The Field is situated on a hillside. The Moqueta Field is primarily accessed by helicopter but is less than 10 kilometres from the Costayaco facilities. There are no material environmental concerns regarding the field's operation or its eventual abandonment. The Field is located within 10 kilometres of the town of Villagarzón in Colombia and is accessed mainly by helicopter. Power, water and other services and equipment are available as needed. Gran Tierra operates the fields in accordance with normal international oilfield practices for occupational health and safety, including ISO 14001 certification.

Twenty-two wells have been drilled in the Moqueta Field to date; the first three in 2010, 16 in 2011 to 2015 and three in 2016. This does not include sidetracks, lost boreholes or wells that ultimately penetrated other thrust sheets. A majority of the wells drilled targeted the Caballos and T Sand with the U Sand as a secondary target, although all production is from the Caballos and T Sand. The Moqueta Field is interpreted to have two main separate fault blocks referred to as the West and East blocks. The West Block is further divided into North and South regions. The West Block commenced commercial production in late 2011, and as of June 2018 was producing approximately 3,500 bopd with a 59 percent water-cut. A water injection project was implemented in the West Block in February 2013. The current water injection rates are approximately 10,900 bwpd. The East Block also commenced production in late 2011 and as of June 2018 was producing approximately 380 bopd with a 46 percent water-cut. A water injection project was implemented in the East Block in early 2016 and current water injection rates are approximately 1,700 bwpd.

All the required facilities are currently in place and the oil produced from the Moqueta Field is delivered via truck and pipeline to a number of delivery points including the OTA pipeline, Ecuador's OCP pipeline and others.

10.2 Geology

The Moqueta Field is located in the north-western part of the Putumayo Basin immediately north of the Costayaco Field. Unlike the Costayaco Field, the Moqueta Field is fully situated in the Andean foothills zone dominated by thrust tectonics. The Urcusique Fault bounds the Moqueta Field to the north and defines the edge of the Andes Mountains in the area. The Moqueta structure occupies the extensively faulted thrust sheet with individual fault blocks displaying variable but significant dips. The Urcusique Fault bounds the Moqueta Field to the north and defines the edge of the Andes Mountains in the area. The structure is bounded in other directions by high angle reverse faults.

Similar to the Costayaco Field, the main productive reservoirs are the Lower Cretaceous Caballos Formation and the T Sandstone Unit of the Cretaceous Albian Villeta Formation.

10.3 Crude Oil Reserves Estimates

The crude oil reserves were based on volumetric, reservoir simulation and performance derived estimates considering all available data including production data, test data, structural and net pay interpretations, reservoir and fluid characteristics, performance of analogous reservoirs and economics of development. A summary of the total economic Moqueta Field reserves by reserves category are presented in Table 18 below.

Crude Oil Reserves at July 31, 2018, Mbbl

	Proved Producing	Proved Developed Non-Producing	Proved Developed	Proved Undeveloped	Total Proved	Probable	Total Proved & Probable	Possible	Total Proved, Probable & Possible
Light and Medium Oil (Mbbl)									
Gross	4,550.1	1,002.0	5,552.1	1,531.5	7,083.5	2,781.8	9,865.3	4,949.2	14,814.5
Net	3,458.2	750.0	4,208.2	1,142.8	5,351.1	2,061.5	7,412.6	3,626.3	11,038.9
Total (MBOE)									
Gross (1)	4,550.1	1,002.0	5,552.1	1,531.5	7,083.5	2,781.8	9,865.3	4,949.2	14,814.5
Net (2)	3,458.2	750.0	4,208.2	1,142.8	5,351.1	2,061.5	7,412.6	3,626.3	11,038.9

(1) Company gross reserves are based on Gran Tierra's working interest reserves before deductions of royalties payable to others.
(2) Net reserves are based on Company share of reserves after royalties and NPI.

Table 18 – Moqueta Field Reserves Summary

10.4 Production Forecasts and Development Plans

All of the facilities have been constructed in the Moqueta Field. Gran Tierra plans to drill two additional infill wells in 2019. A number of wells in the field have experienced water breakthrough and as the water-cut trends in the field begin to form, oil production rates will be heavily dependent on the overall fluid rates. Production rates in June 2018 were approximately 3,900 bopd.

10.5 Net Present Value Estimates

The net present values of the crude oil reserves were based on future production and revenue analyses. All of the revenues and costs presented in this report were presented in USD.

The future crude oil revenue was derived by employing the future production forecast for each reserves category and the McDaniel July 1, 2018 forecast of future crude oil prices. McDaniel reviewed the percentage of production sold to various delivery points and the actual prices received for six months of 2018 as well as information provided by Gran Tierra on expected prices and delivery routes for the remainder of 2018 and going forward.

Government share of revenues is through a sliding scale royalty and HPR, as well as an NPI of 10 percent. Operating costs were based on a combination of the 2018 accounting and our experience of analogous oil projects. Capital costs were based on the 2018/2019 budget provided by Gran Tierra. An allowance was made for well abandonment costs at the end of each respective forecast.

A summary of the before tax and after tax net present value estimates are presented in Table 19 and Table 20 below respectively.

Before Tax Net Present Values at July 31, 2018, US$MM (1) (2)

	Discounted At				
	0%	5%	10%	15%	20%
Proved Producing Reserves	81.3	75.6	70.6	66.1	62.2
Proved Developed Non-Producing	24.2	20.5	17.6	15.3	13.4
Proved Developed Reserves	105.5	96.1	88.2	81.4	75.7
Proved Undeveloped Reserves	23.9	18.1	13.7	10.3	7.7
Total Proved Reserves	129.4	114.2	101.8	91.7	83.4
Probable Reserves	69.6	54.0	43.0	35.1	29.3
Proved + Probable Reserves	199.0	168.2	144.8	126.8	112.6
Possible Reserves	130.5	89.5	64.7	49.0	38.6
Proved + Probable + Possible	329.5	257.7	209.5	175.8	151.2

(1) Based on forecast prices and costs at July 1, 2018 (see Table 9).
(2) The net present values may not necessarily represent the fair market value of the reserves.

Table 19 – Moqueta Field Before Tax Net Present Value Summary of the Reserves

After Tax Net Present Values at July 31, 2018, US$MM (1) (2)

	Discounted At				
	0%	5%	10%	15%	20%
Proved Producing Reserves	63.7	59.3	55.3	51.8	48.6
Proved Developed Non-Producing	15.7	13.4	11.6	10.1	8.9
Proved Developed Reserves	79.4	72.7	66.9	61.9	57.5
Proved Undeveloped Reserves	15.1	10.9	7.7	5.3	3.4
Total Proved Reserves	94.4	83.6	74.6	67.1	60.9
Probable Reserves	44.8	35.1	28.0	22.9	19.1
Proved + Probable Reserves	139.2	118.7	102.6	90.0	80.0
Possible Reserves	83.9	58.0	42.1	31.9	25.1
Proved + Probable + Possible	223.1	176.7	144.7	121.9	105.1

(1) Based on forecast prices and costs at July 1, 2018.
(2) The net present values may not necessarily represent the fair market value of the reserves.

Table 20– Moqueta Field After Tax Net Present Value Summary of the Reserves

11 OTHER FIELDS

11.1 Property Overview

The remaining fields assigned reserves are the Cumplidor, Guriyaco, Guayuyaco, Juanambu, Nancy-Burdine-Maxine, Mary-Miraflor-Toroyaco, Vonu and Suroriente fields in the Putumayo Basin, the Jilguero and Ramiriqui fields in the Llanos Basin, and the Chuira, Colon, Juglar, Los Angeles, Mochuelo, Mono Arana and Querubin fields in the Middle Magdalena Valley Basin. Gran Tierra's minor assets are all located onshore and accessed by road. There are no material environmental concerns regarding the fields' operation or their eventual abandonment. Power, water and other services and equipment are available as needed. Those fields operated by Gran Tierra are operated in accordance with normal international oilfield practices for occupational health and safety, including ISO 14001 certification. In fields not operated by Gran Tierra, it looks for its partners to implement similar standards to its own.

11.2 Geology

The main potential in the other Putumayo Basin fields is associated with the Lower Cretaceous Caballos Formation, the T and U sandstone units of the Villeta Formation, as well as the Upper Cretaceous N Sand. The main potential in the other MMV Basin fields is associated with the Lisama, Umir, La Paz and Arenas Basales formations. The main potential in the other Llanos Basin fields is associated with the Eocene Mirador and the Cretaceous Gacheta and Une reservoirs.

11.3 Crude Oil Reserves Estimates

The crude oil reserves were based on volumetric, reservoir simulation and performance derived estimates considering all available data including production data, test data, seismic and net pay interpretations, reservoir and fluid characteristics, performance of analogous reservoirs and economics of development. A summary of the total economic reserves by reserves category are presented in Table 21 below.

Crude Oil Reserves at July 31, 2018, Mbbl

	Proved Producing	Proved Developed Non-Producing	Proved Developed	Proved Undeveloped	Total Proved	Probable	Total Proved & Probable	Possible	Total Proved, Probable & Possible
Light and Medium Oil (Mbbl)									
Gross	5,356.8	3,302.6	8,659.4	3,234.0	11,893.5	10,927.5	22,821.0	15,095.8	37,916.8
Net	4,756.3	2,734.2	7,490.5	2,706.2	10,187.0	9,233.2	19,420.2	11,632.0	31,052.2
Heavy Oil (Mbbl)									
Gross	2,126.2	50.8	2,177.0	1,897.2	4,074.1	6,717.5	10,791.6	8,127.7	18,919.3
Net	1,833.1	37.2	1,870.3	1,607.3	3,487.0	5,161.1	8,648.1	5,385.6	14,033.7
Natural Gas (MMcf)									
Gross	1,473.8	-	1,473.8	791.8	2,265.6	1,303.4	3,569.0	1,655.9	5,224.9
Net	1,379.5	-	1,379.5	741.1	2,120.6	1,220	3,340.6	1,549.9	4,890.5
Total (MBOE)									
Gross (1)	7,728.7	3,353.4	11,082.1	5,263.1	16,345.2	17,862.3	34,207.5	23,499.3	57,706.8
Net (2)	6,819.3	2,771.4	9,590.7	4,437.0	14,027.5	14,597.6	28,625.1	17,275.9	45,901.0

(1) Company gross reserves are based on Gran Tierra's working interest reserves before deductions of royalties payable to others.
(2) Net reserves are based on Company share of reserves after royalties and NPI.

Table 21 – Other Fields Reserves Summary

11.4 Production Forecasts and Development Plans

The 1P, 2P and 3P forecasts are based on Gran Tierra's development plans for the other fields, and include the drilling of 19, 42 and 67 new wells on a 1P, 2P and 3P basis, as well as 13 recompletions on a 1P, 2P and 3P basis.

11.5 Net Present Value Estimates

The net present values of the crude oil reserves were based on future production and revenue analyses. All of the revenues and costs presented in this report were presented in US Dollars.

The future crude oil revenue was derived by employing the future production forecast for each reserves category and the McDaniel July 1, 2018 forecast of future crude oil prices. McDaniel reviewed the percentage of production sold to various delivery points and the actual prices received for six months of 2018 as well as information provided by Gran Tierra on expected prices and delivery routes for the remainder of 2018 and going forward.

Operating costs were based on a combination of the 2018 accounting and our experience of analogous oil projects. Capital costs were based on the 2018/2019 budget provided by Gran Tierra. An allowance was made for well abandonment costs at the end of each respective forecast.

A summary of the before tax and after tax net present value estimates are presented in Table 22 and Table 23 below respectively.

Before Tax Net Present Values at July 31, 2018, US$MM (1) (2)	Discounted At				
	0%	5%	10%	15%	20%
Proved Producing Reserves	210.8	190.6	174.3	161.0	149.9
Proved Developed Non-Producing	89.0	73.8	62.5	53.9	47.3
Proved Developed Reserves	299.7	264.3	236.8	214.9	197.2
Proved Undeveloped Reserves	71.5	51.9	36.6	24.6	15.1
Total Proved Reserves	371.3	316.2	273.4	239.5	212.3
Probable Reserves	519.5	390.9	301.5	237.6	190.7
Proved + Probable Reserves	890.8	707.1	574.9	477.1	403.0
Possible Reserves	701.3	498.8	368.2	280.4	219.3
Proved + Probable + Possible	1,592.0	1,205.9	943.0	757.5	622.4

(1) Based on forecast prices and costs at July 1, 2018 (see Table 9).
(2) The net present values may not necessarily represent the fair market value of the reserves.

Table 22 – Other Fields Before Tax Net Present Value Summary of the Reserves

After Tax Net Present Values at July 31, 2018, US$MM (1) (2)	Discounted At				
	0%	5%	10%	15%	20%
Proved Producing Reserves	183.0	166.2	152.4	141.0	131.4
Proved Developed Non-Producing	64.1	53.4	45.4	39.2	34.4
Proved Developed Reserves	247.1	219.6	197.8	180.2	165.8
Proved Undeveloped Reserves	56.1	34.9	21.7	11.4	3.2
Total Proved Reserves	303.2	254.5	219.5	191.6	169.1
Probable Reserves	383.1	286.9	218.5	169.5	133.6
Proved + Probable Reserves	686.2	541.3	437.9	361.1	302.7
Possible Reserves	523.1	371.2	271.4	204.4	158.0
Proved + Probable + Possible	1,209.4	912.6	709.4	565.5	460.7

(1) Based on forecast prices and costs at July 1, 2018.
(2) The net present values may not necessarily represent the fair market value of the reserves.

Table 23 – Other Fields After Tax Net Present Value Summary of the Reserves

12 CRUDE OIL PROSPECTIVE RESOURCES ESTIMATES

McDaniel conducted a review of all available seismic, log, and general geological data provided by Gran Tierra for existing wells in the Blocks, the surrounding area and for the exploration prospects and leads identified by Gran Tierra. As mentioned earlier, Gran Tierra has provided an extensive data set and McDaniel has reviewed several wells and discoveries in the various areas. The discoveries in the Blocks provide valuable information on the expected parameters for the various exploration targets.

In the Putumayo Basin, 26 drillable stratigraphic structures in the N Sand and nine (including structures with multi-zone potential for a total of 12 pools) drillable structures in the Caballos, T and U sands were identified by Gran Tierra and assessed by McDaniel. In addition, 12 blocks were assessed for resources in the A Limestone in the Putumayo Basin using a deterministic regional approach. In the Llanos Basin, a total of 19 drillable structures (including structures with multi-zone potential for a total of 43 pools) were identified by Gran Tierra and assessed by McDaniel. In the Sinu Basin, two drillable structures were identified by Gran Tierra and assessed by McDaniel. In the MMV Basin, a total of nine drillable structures (including structures with multi-zone potential for a total of 10 pools) were identified by Gran Tierra and assessed by McDaniel.

12.1 Prospective Resources Input Parameters

All of the prospective resources assigned as part of this assessment have been estimated probabilistically as this is the most appropriate method given the high degree of uncertainty in the various input parameters. Distributions of the various reservoir and fluid parameters were determined, based on parameters from existing wells/discoveries in the area or general worldwide data, and probabilistic calculations of the unrisked original oil-in-place ("OOIP") / original gas-in-place ("OGIP") and recoverable resources were prepared for each prospect/lead.

Both the OOIP/OGIP and prospective resources distributions were derived using Monte-Carlo simulation for each zone within a prospect/lead, with the exception of the A Limestone prospective resources in the Putumayo Basin. The various zones assigned to each prospect were then aggregated probabilistically to the prospect/lead level and aggregated arithmetically to the total level.

12.2 Chance of Success

The prospects were risked using five parameters: source, migration, reservoir, structure (or trap) and seal. The overall geological chance of success is the product of these individual parameters and was used to determine the risked mean resources, prior to applying the chance of development. The most significant geological risk for the N Sand prospects in the Putumayo Basin is the structure, relating to the seismic coverage, data quality and presence that the seismic anomaly exists. For the structural prospects in the Putumayo Basin, the main geological risk is a combination of structure and seal. For the prospects in the Llanos Basin, the main geological risks vary by prospect and in some cases, migration is the critical risk or else a combination of structure and seal. Due to the early exploration stage of the Sinu Basin, these leads have higher geological risk than the prospects identified in the other two basins. In the MMV Basin the critical risks vary among reservoir, structure and seal.

Source and reservoir were the critical risks factored into the geological chance of success for the A Limestone. A review of the source data including TOC, S1 and S1/TOC ratio were assessed to ultimately determine the source factor while the reservoir risk was heavily dependent on the degree of potential natural fracturing in the area to ensure producibility of the reservoir.

12.3 Chance of Development

A chance of development has also been applied to prospects/leads within the four basins. The chance of development is defined as the probability of a project being commercially viable. Quantifying the chance of development requires consideration of both economic contingencies and other contingencies, such as legal, regulatory, market access, political, social licence, internal and external approvals and commitment to project finance and development timing. As many of these factors are extremely difficult to quantify, the chance of development is uncertain and must be used with caution. As a rule, a project will have an increased chance of development as it passes up the project maturity sub-classes.

As many of the prospects in the Putumayo, Llanos and Middle Magdalena Valley basins are located nearby existing discoveries it is expected that any discoveries would be likely to proceed with development and be relatively straightforward to monetize. Gran Tierra does not foresee any regulatory hurdles should any of these prospects become a discovery. The leads located in the Sinu Basin; however, present additional challenges due to the lack of nearby infrastructure. After considering all of the relevant factors, including the uncertain economic status, the chance of development was estimated to range from 70 to 90 percent for the majority of prospects in the Putumayo, Llanos and Middle Magdalena Valley basins and 50 to 60 percent in the Sinu Basin.

A summary of the resulting unrisked prospective resources and risked mean resources by main sub-type/basin is presented in Tables 6 and 7 earlier in the report.

13 RESERVES VALUATION SENSITIVITY

Additional revenue forecasts have been prepared to illustrate the sensitivity of net present values to the base case pricing assumptions. Sensitivities were prepared by altering the WTI and Brent crude oil forecast 10 percent higher and 10 percent lower and a summary of the resulting net present values is presented in Table 24 below.

	10 Percent Net Present Values at July 1, 2018 (US$M) Based on Pricing Case:		
	-10% of Base	**Base Price Case(1)**	**+10% of Base**
Before Income Taxes (2)			
Proved Reserves	1,179,762.8	1,482,740.9	1,788,796.6
Probable Reserves	1,020,249.00	1,238,423.90	1,457,031.00
Total Proved + Probable Reserves	2,200,011.8	2,721,164.8	3,245,827.6
Possible Reserves	1,026,180.50	1,198,657.90	1,402,164.90
Total Proved + Probable + Possible Reserves	3,226,192.3	3,919,822.7	4,647,992.5
After Income Taxes (2)			
Proved Reserves	964,907.1	1,174,044.6	1,382,860.8
Probable Reserves	693,015.60	842,286.10	993,352.40
Total Proved + Probable Reserves	1,657,922.7	2,016,330.7	2,376,213.2
Possible Reserves	702,413.00	812,211.50	953,733.60
Total Proved + Probable + Possible Reserves	2,360,335.7	2,828,542.2	3,329,946.8

(1) Base price based on forecast prices and costs at July 1, 2018 (see Table 9).
(2) The net present values may not necessarily represent the fair market value of the reserves.

Table 24 – Gran Tierra Net Present Value Sensitivity Summary

14 ABBREVIATIONS

The following is a glossary of technical terms and a list of the abbreviations used in this report:

Term/Abbreviation	Meaning
"2D Seismic"	seismic data acquired in a grid of lines that is relatively broad spaced, and is processed in two dimensions
"3D Seismic"	seismic data acquired in a grid that is relatively close-spaced and dense, and is processed in three dimensions
"AAPG"	American Association of Petroleum Geology
"abandonment"	a term to describe the sealing of a well with cement plugs, and removing the wellhead with no intention of re-entering the well
"AIM"	Alternative Investment Market on the London Stock Exchange
"anticline"	a hydrocarbon trap where the reservoir has a convex geometry
"API"	a specific gravity scale development by the American Petroleum Institute for measuring the relative density of various petroleum fluids, expressed in degrees
"bbl"	one barrel of oil; 1 barrel = 35 Imperial gallons (approx.), or 159 litres (approx.); 7.5 barrels = 1 tonne (approximately depending upon the oil density); 6.29 barrels = 1 cubic metre
"bbl/MMcf"	barrels per million of cubic feet
"Bcf"	billion cubic feet
"block"	term commonly used to describe contract areas or tract, as in "block of land"
BOE	barrels of oil equivalent
"borehole"	the wellbore including the uncased potion of the well
"bopd"	barrels of oil production per day
"bpd"	barrels per day
"bwpd"	barrels of water production per day
"carbonate"	class of sedimentary rocks which mainly contains calcite, aragonite and dolomite.
"chance of discovery"	the chance that the potential accumulation will result in the discovery of petroleum
Clastic	rock series consisting of predominantly sedimentary rock made up of clasts (fragments) derived from pre-existing rocks transported and re-deposited before becoming lithified
"completion"	the operation of perforating, stimulating and equipping an oil or gas well
"condensate"	hydrocarbons which are in the gaseous state under reservoir conditions and which become liquid when temperature or pressure is reduced. A mixture of pentanes and higher hydrocarbons
"contingent resources"	quantities of petroleum estimated, as at a given date, to be potentially recoverable from known accumulations, but applied project(s) are not yet considered mature enough for commercial development due to one of more contingencies
"core analysis"	laboratory study of a sample of a geologic formation, usually reservoir rock, taken during or after drilling a well
"Cretaceous"	geological strata formed during the period 140 million to 65 million years ago
"cost oil"	the sum of a party's investment and operating costs recovered from the production of oil from the relevant field
"CPR"	Competent Person's Report
"discovery"	A defined term under PRMS. "A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons."

Term/Abbreviation	Meaning
"exploration phase"	the phase of operations which covers the search for oil or gas by carrying out detailed geological and geophysical surveys followed up where appropriate by exploratory drilling
"exploration well"	a well in an unproven area or prospect, may also be known as a "wildcat well"
"fault"	a break in the earth's crust where there has been displacement of one side relative to the other. Sometimes a layer of non-porous rock may be next to an oil-bearing porous interval along a fault and form a trap for the oil
"FEED"	front end engineering design
"field"	a geographical area under which an oil or gas reservoir lies
"formation"	a unit of rock
"gas field"	a field containing natural gas but no oil
"HPR"	high price royalty
"hydrocarbon"	a compound containing only the elements hydrogen and carbon. May exist as a solid, a liquid or a gas. The term is mainly used in a catch-all sense for oil, gas and condensate
"IPO"	Initial public offering
"Jurassic"	geological strata (or period) formed during the period from 144 million to 205 million years ago
"km"	Kilometres
km^2	square kilometres
"M"	Thousands
"m"	Metres
"MM"	Millions
"Mbbl"	thousands of barrels
"MMbbl"	millions of barrels
"Mcfpd"	thousands of cubic feet per day
"MMcfpd"	millions of cubic feet per day
NPI	net profit interest
"natural gas"	gas, occurring naturally, and often found in association with crude petroleum
"net pay"	the total thickness of hydrocarbon bearing sediments that is classified as reservoir
"oil"	a mixture of liquid hydrocarbons of different molecular weights
"oil field"	a geographic area under which an oil reservoir lies
"OGIP"	original gas in place
"OOIP"	original oil in place
"operator"	the company that has legal authority to undertake petroleum operations.
"P10"	the term used to describe the volume of reserves defined as having a better than 10% chance of being technically and economically viable.
"P50"	the term used to describe the volume of reserves defined as having a better than 50% chance of being technically and economically viable.
"P90"	the term used to describe the volume of reserves defined as having a better than 90% chance of being technically and economically viable.
"permeability"	the property of a formation which quantifies the flow of a fluid through the pore spaces and into the wellbore
"petroleum"	a generic name for hydrocarbons, including crude oil, natural gas liquids, natural gas and their products
"pool"	an individual and separate accumulation of petroleum in a reservoir

Term/Abbreviation	Meaning
"porosity"	the percentage of void in a porous rock compared to the total rock volume
"PRMS"	Petroleum Resource Management System
"probabilistic"	a method of estimating an uncertain outcome whereby a range of values is used for each parameter in a calculation. Results are generally expressed as a range with an associated probability of occurrence
"profit oil"	means a party's share of production from the relevant field in excess of Cost Oil
"property gross"	the total reserves or resources for the property
"prospective resources"	quantities of petroleum estimated, as at a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development
"PSC"	a production sharing contract
"PVT"	pressure-volume-temperature relationship for fluid
"reserves"	generally the amount of economically recoverable oil or gas in a particular reservoir that is available for production
"reservoir"	the underground formation where oil and gas has accumulated. It consists of a porous and permeable rock to hold the oil or gas, and a cap rock that prevents its escape
"risked"	after accounting for chance of success or discovery
"SPE"	Society of Petroleum Engineers
"SPEE"	Society of Petroleum Evaluation Engineers
"spud" or "spudded"	means the commencement of drilling operations by the initial penetration of the ground
"structural high"	an area where rocks have been elevated due to tectonic activity
"TD"	total depth of a well, when drilling has finished
"Triassic"	geological period between 250 and 205 million years ago
"US$"	United States dollars
"US$ M"	thousands United States dollars
"US$ MM"	millions United States dollars
"unrisked"	prior to taking into account the chance of discovery
"well log"	a record of geological formation penetrated during drilling, including technical details of the operation
"WPC"	World Petroleum Congress
"zone"	a general term meaning an interval or unit of rock. A zone in a well would be an interval typically defined by a top and bottom depth. A fault zone would be the unit of rock associated and the area around a fault

15 PROFESSIONAL QUALIFICATIONS

McDaniel & Associates Consultants Ltd. has over 60 years of experience in the evaluation of oil and gas properties. McDaniel & Associates Consultant Ltd. is registered with the Association of Professional Engineers and Geoscientists of Alberta ("APEGA"). Mr. Cam Boulton, Executive Vice President, and Mr. Anatoli Tchernavskikh, Manager International Geology, all with McDaniel & Associates, supervised the preparation of this report. Mr. Boulton has over 12 years of experience in the evaluation of oil and gas properties, Mr. Anatoli Tchernavskikh has in excess of 25 years, Mr. Mikhail Alexeev has in excess of 15 years, and Mr. Nathan Koshka has in excess of 2 years of experience. All of the persons involved in the preparation of this report and McDaniel & Associates are independent of Gran Tierra.

In preparing this report, we relied upon certain factual information including ownership, technical well data, production data, and other relevant data supplied by the Company. The extent and character of all factual information supplied were relied upon by us in preparing this report and has been accepted as represented without independent verification. We have relied upon representations made by the Company as to the completeness and accuracy of the data provided and that no new data has come to light that may result in a material change to the evaluation of the reserves and prospective resources presented herein.

This report was prepared by McDaniel & Associates Consultants Ltd. for the use of Gran Tierra Energy Inc. under the terms of our engagement agreement dated July 16, 2018. We reserve the right to revise any estimates provided herein if any relevant data existing prior to preparation of this letter was not made available, if any data between the effective date of the assessment and the date of this letter were to vary significantly from that forecast, or if any data provided was found to be erroneous.

Sincerely,

McDANIEL & ASSOCIATES CONSULTANTS LTD.
APEGA PERMIT NUMBER: P3145

C. Boulton, P. Eng.
Executive Vice President

for
N. Koshka, E.I.T.
Evaluation Engineer

A. Tchernavskikh, P. Geol.
Manager, International Geology

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[18-0176]

GRAN TIERRA ENERGY INC.

TABLE OF CONTENTS

APPENDIX 1

Prices: McDaniel Jul 2018
Eff. Date: July 31, 2018
Currency: USD

Table A

Gran Tierra Energy Inc.

Total Company Reserves and Net Present Value
Forecast Prices and Costs as of July 31, 2018

Total Company

	PDP	PNP	PUD	TP	PPDP	PPNP	PPUD	TPP	PPPDP	PPPNP	PPPUD	TPPP
Light and Medium Oil (Mbbl)												
Working Interest Volume	29,182.2	5,545.0	8,185.0	**42,912.3**	41,568.6	7,505.5	22,525.6	**71,599.7**	57,355.0	10,140.1	45,244.8	**112,739.8**
Royalty Interest Volume	-	-	-	**-**	-	-	-	**-**	-	-	-	**-**
Net Volume	23,299.0	4,423.6	6,544.6	**34,267.2**	32,961.6	5,949.0	18,242.7	**57,153.3**	45,104.3	7,990.5	35,406.3	**88,501.0**
Heavy Oil (Mbbl)												
Working Interest Volume	13,969.3	50.8	12,987.4	**27,007.5**	20,026.0	66.0	44,829.5	**64,921.5**	27,495.9	462.0	68,300.1	**96,258.1**
Royalty Interest Volume	-	-	-	**-**	-	-	-	**-**	-	-	-	**-**
Net Volume	11,528.1	37.2	10,748.6	**22,313.9**	16,429.9	44.1	36,093.0	**52,566.9**	22,387.1	359.0	53,393.5	**76,139.6**
Natural Gas (MMcf)												
Working Interest Volume	1,473.8	-	791.8	**2,265.6**	1,808.5	-	1,760.5	**3,569.0**	2,250.7	-	2,974.2	**5,224.9**
Royalty Interest Volume	-	-	-	**-**	-	-	-	**-**	-	-	-	**-**
Net Volume	1,379.5	-	741.1	**2,120.6**	1,692.8	-	1,647.8	**3,340.6**	2,106.6	-	2,783.8	**4,890.5**
Natural Gas Liquids (Mbbl)												
Working Interest Volume	-	-	-	**-**	-	0.0	-	**0.0**	-	-	-	**-**
Royalty Interest Volume	-	-	-	**-**	-	-	-	**-**	-	-	-	**-**
Net Volume	-	-	-	**-**	-	0.0	-	**0.0**	-	-	-	**-**
Total (MBOE) (1)												
Working Interest Volume	43,397.2	5,595.8	21,304.3	**70,297.4**	61,896.0	7,571.5	67,648.5	**137,116.1**	85,226.0	10,602.1	114,040.6	**209,868.7**
Royalty Interest Volume	-	-	-	**-**	-	-	-	**-**	-	-	-	**-**
Net Volume	35,057.0	4,460.9	17,416.7	**56,934.6**	49,673.6	5,993.1	54,610.3	**110,277.0**	67,842.5	8,349.5	89,263.8	**165,455.7**
Net Present Value Before Tax (M$)												
0.0%	1,270,886.4	145,939.9	493,930.4	**1,910,756.7**	1,853,550.6	212,009.9	2,088,555.0	**4,154,115.5**	2,395,903.9	309,912.3	3,736,305.2	**6,442,121.5**
5.0%	1,154,323.3	122,528.5	394,608.4	**1,671,460.2**	1,612,675.3	171,357.8	1,521,528.7	**3,305,561.9**	2,062,732.0	239,251.7	2,623,851.9	**4,925,835.7**
10.0%	1,058,997.4	104,894.6	318,848.9	**1,482,740.9**	1,429,127.1	142,327.3	1,149,710.3	**2,721,164.8**	1,791,963.9	191,727.2	1,936,131.6	**3,919,822.7**
15.0%	979,942.6	91,315.3	259,999.6	**1,331,257.5**	1,285,734.8	120,951.4	893,957.3	**2,300,643.5**	1,579,444.6	158,449.5	1,483,042.6	**3,220,936.6**
20.0%	913,532.1	80,644.8	213,517.2	**1,207,694.1**	1,171,226.6	104,774.3	710,858.8	**1,986,859.7**	1,412,534.4	134,290.6	1,168,871.1	**2,715,696.1**
$/BOE Before Tax (2)												
0.0%	29.28	26.08	23.18	**27.18**	29.95	28.00	30.87	**30.30**	28.11	29.23	32.76	**30.70**
5.0%	26.60	21.90	18.52	**23.78**	26.05	22.63	22.49	**24.11**	24.20	22.57	23.01	**23.47**
10.0%	24.40	18.75	14.97	**21.09**	23.09	18.80	17.00	**19.85**	21.03	18.08	16.98	**18.68**
15.0%	22.58	16.32	12.20	**18.94**	20.77	15.97	13.21	**16.78**	18.53	14.95	13.00	**15.35**
20.0%	21.05	14.41	10.02	**17.18**	18.92	13.84	10.51	**14.49**	16.57	12.67	10.25	**12.94**
Net Present Value After Tax (M$)												
0.0%	1,086,019.9	101,239.5	336,220.9	**1,523,480.3**	1,481,511.8	142,233.6	1,439,486.7	**3,063,232.1**	1,781,502.2	205,957.6	2,593,337.8	**4,580,797.6**
5.0%	985,169.5	85,347.4	256,418.7	**1,326,935.6**	1,297,780.3	115,939.4	1,031,576.1	**2,445,295.9**	1,575,318.3	160,095.0	1,802,417.7	**3,537,831.0**
10.0%	902,073.7	73,220.5	198,750.4	**1,174,044.6**	1,155,414.7	96,849.9	764,066.1	**2,016,330.7**	1,389,339.3	128,901.0	1,310,301.9	**2,828,542.2**
15.0%	832,780.1	63,794.4	153,962.9	**1,050,537.4**	1,042,642.1	82,621.5	579,392.3	**1,704,655.8**	1,236,055.8	106,901.6	984,944.7	**2,327,902.1**
20.0%	774,333.5	56,337.0	118,644.4	**949,314.9**	951,533.4	71,753.2	447,026.9	**1,470,313.5**	1,112,159.1	90,848.2	759,141.7	**1,962,149.0**

(1) Barrels of Oil Equivalent based on 6:1 for Natural Gas, 1:1 for Condensate and C5+, 1:1 for Ethane,1:1 for Propane, 1:1 for Butanes. BOE's 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.
(2) NPV/BOE based on Company Share BOE reserves.

Prices: McDaniel Jul 2018
Eff. Date: July 31, 2018
Currency: USD

Gran Tierra Energy Inc.

Table 2

Forecast of Production and Revenue - Company Share
Forecast Prices and Costs as of July 31, 2018
Proved Developed Producing Reserves

Total Company

Year	Property Gross: No. Of Wells	Property Gross: Crude Oil bbl/d	Property Gross: Natural Gas Mcf/d	Property Gross: NGL bbl/d	Property Gross: Total BOE/d	Crude Oil: Annual Volume Mbbl	Crude Oil: Sales Price $/bbl	Crude Oil: Sales Revenue M$	Natural Gas: Annual Volume MMcf	Natural Gas: Sales Price $/Mcf	Natural Gas: Sales Revenue M$	Natural Gas Liquids: Annual Volume Mbbl	Natural Gas Liquids: Sales Price $/bbl	Natural Gas Liquids: Sales Revenue M$	Other Revenue M$	Sales Revenue M$
2018 (5)	111.0	44,682	2,455	-	45,091	5,485	64.01	351,067	168	3.67	617	-	-	-	-	351,684
2019	109.7	35,613	1,956	-	35,939	10,533	58.39	615,016	321	3.67	1,179	-	-	-	-	616,196
2020	106.5	26,251	1,470	-	26,496	7,799	58.55	456,694	242	3.67	889	-	-	-	-	457,582
2021	102.8	19,837	1,126	-	20,024	5,884	59.79	351,776	185	3.67	679	-	-	-	-	352,455
2022	97.6	15,234	873	-	15,380	4,535	63.76	289,140	143	3.67	526	-	-	-	-	289,667
2023	65.5	9,901	705	-	10,018	3,352	65.20	218,557	116	3.67	425	-	-	-	-	218,982
2024	58.6	7,526	576	-	7,622	2,586	66.64	172,316	95	3.67	348	-	-	-	-	172,665
2025	46.5	5,083	477	-	5,163	1,718	67.79	116,455	78	3.67	287	-	-	-	-	116,742
2026	29.1	2,490	398	-	2,557	796	68.51	54,526	65	3.67	240	-	-	-	-	54,766
2027	13.0	853	336	-	909	224	70.87	15,891	55	3.67	203	-	-	-	-	16,094
2028	8.7	362	26	-	367	111	72.97	8,095	4	3.67	16	-	-	-	-	8,111
2029	5.7	232	-	-	232	75	74.46	5,574	-	-	-	-	-	-	-	5,574
2030	4.0	118	-	-	118	34	73.63	2,525	-	-	-	-	-	-	-	2,525
2031	2.0	34	-	-	34	12	74.22	926	-	-	-	-	-	-	-	926
2032	1.3	21	-	-	21	8	75.76	581	-	-	-	-	-	-	-	581
Rem.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**-**	**-**	**-**	**-**	**-**	**43,152**	**61.62**	**2,659,141**	**1,474**	**3.67**	**5,409**	**-**	**-**	**-**	**-**	**2,664,549**
@10.0%	-	-	-	-	-	-	48.49	2,092,375	-	2.80	4,129	-	-	-	-	2,096,504

Year	Royalties: State Royalty Oil M$	Royalties: State Royalty Gas M$	Royalties: HPS M$	Royalties: Other Roy. & Burdens M$	Royalties: Total M$	Royalties: Total %	Net Volumes: Oil Mbbl	Net Volumes: Gas MMcf	Net Volumes: Liquids Mbbl	Net Interest Revenue M$	Other Revenue M$
2018 (5)	29,702	39	34,799	5,826	70,366	20.0	4,390	157	-	281,318	3,167
2019	51,015	75	56,550	9,365	117,005	19.0	8,538	301	-	499,190	6,730
2020	37,079	57	43,145	6,282	86,563	18.9	6,327	227	-	371,019	4,832
2021	28,272	43	34,818	4,376	67,510	19.2	4,759	173	-	284,945	3,521
2022	23,149	34	30,801	3,342	57,325	19.8	3,639	134	-	232,341	2,700
2023	17,269	27	24,969	2,144	44,409	20.3	2,673	108	-	174,573	2,057
2024	13,666	22	20,257	1,280	35,225	20.4	2,058	89	-	137,439	1,657
2025	9,288	18	13,221	591	23,119	19.8	1,378	73	-	93,623	1,190
2026	4,417	15	4,848	141	9,421	17.2	658	61	-	45,345	707
2027	1,615	13	336	107	2,071	12.9	195	52	-	14,022	179
2028	984	1	-	39	1,024	12.6	97	4	-	7,086	82
2029	702	-	-	19	721	12.9	65	-	-	4,853	49
2030	202	-	-	18	220	8.7	31	-	-	2,305	45
2031	74	-	-	-	74	8.0	11	-	-	852	-
2032	46	-	-	-	46	8.0	7	-	-	535	-
Rem.	-	-	-	-	-	-	-	-	-	-	-
Total	**217,482**	**346**	**263,744**	**33,529**	**515,101**	**19.3**	**34,827**	**1,379**	**-**	**2,149,448**	**26,915**
@10.0%	171,399	264	206,357	27,738	405,759	19.4	-	-	-	1,690,745	21,192

Year	Operating Costs M$	Operating Costs $/BOE	Abd. & Recl. Costs M$	Net Op. Income M$	Capital Costs M$	Future Net Revenue Before Tax: Annual M$	Future Net Revenue Before Tax: Cum. M$	Future Net Revenue Before Tax: NPV @10.0% M$	Taxes Payable M$	After Tax: Annual M$	After Tax: NPV @10.0% M$
2018 (5)	63,389	11.50	-	221,097	5,902	215,195	215,195	211,085	50,177	165,018	161,318
2019	138,481	13.08	-	367,439	2,188	365,251	580,446	335,762	64,004	301,247	277,090
2020	125,647	16.03	-	250,204	-	250,204	830,650	209,129	26,898	223,306	186,713
2021	116,746	19.74	630	171,090	-	171,090	1,001,740	129,998	7,092	163,998	124,625
2022	110,458	24.23	726	123,858	-	123,858	1,125,598	85,570	1,360	122,498	84,633
2023	95,199	28.24	430	81,001	-	81,001	1,206,599	50,897	9,387	71,614	45,020
2024	88,727	34.11	5,103	45,266	-	45,266	1,251,865	25,797	14,477	30,788	17,556
2025	69,820	40.33	906	24,086	-	24,086	1,275,951	12,546	7,302	16,784	8,767
2026	36,039	44.67	11,499	-1,486	-	-1,486	1,274,465	-596	2,842	-4,328	-1,933
2027	11,560	49.53	885	1,756	-	1,756	1,276,220	753	676	1,080	464
2028	5,857	52.46	4,735	-3,424	-	-3,424	1,272,796	-1,404	361	-3,785	-1,545
2029	4,304	57.50	1,145	-548	-	-548	1,272,249	-190	176	-723	-252
2030	2,102	61.29	379	-130	-	-130	1,272,118	-38	78	-208	-63
2031	762	61.01	542	-452	-	-452	1,271,667	-125	30	-482	-134
2032	514	67.04	-	20	-	20	1,271,687	6	7	14	4
Rem.	-	-	801	-801	-	-801	-801	-191	-	-801	-191
Total	**869,606**	**-**	**27,781**	**1,278,976**	**8,090**	**1,270,886**	**-**	**1,058,997**	**184,866**	**1,086,020**	**902,074**
@10.0%	631,949	-	13,222	1,066,766	7,769	1,058,997	-	-	156,924	902,074	-

Product	Remaining Reserves: Gross Lease	Remaining Reserves: W.I.	Remaining Reserves: R.I.	Remaining Reserves: Net
Light and Medium Oil (Mbbl)	32,418	29,182	-	23,299
Heavy Oil (Mbbl)	19,510	13,969	-	11,528
Natural Gas (MMcf)	3,275	1,474	-	1,379
Total (MBOE)	**52,473**	**43,397**	**-**	**35,057**

RLI	3.08 yrs
Remaining Life	14.08 yrs
Price Schedule	G180701

Net Present Value - M$	@ 0.0%	@ 5.0%	@ 10.0%	@ 15.0%	@ 20.0%
Before Taxes	1,270,886	1,154,323	1,058,997	979,943	913,532
After Taxes	**1,086,020**	**985,169**	**902,074**	**832,780**	**774,334**

McDaniel & Associates Consultants Ltd.

Prices: McDaniel Jul 2018
Eff. Date: July 31, 2018
Currency: USD

Gran Tierra Energy Inc.

Table 3

Forecast of Production and Revenue - Company Share
Forecast Prices and Costs as of July 31, 2018
Proved Developed Reserves

Total Company

Year	Property Gross No. Of Wells	Property Gross Crude Oil bbl/d	Property Gross Natural Gas Mcf/d	Property Gross NGL bbl/d	Property Gross Total BOE/d	Crude Oil Annual Volume Mbbl	Crude Oil Sales Price $/bbl	Crude Oil Sales Revenue M$	Natural Gas Annual Volume MMcf	Natural Gas Sales Price $/Mcf	Natural Gas Sales Revenue M$	Natural Gas Liquids Annual Volume Mbbl	Natural Gas Liquids Sales Price $/bbl	Natural Gas Liquids Sales Revenue M$	Other Revenue M$	Sales Revenue M$
2018 (5)	118.8	46,025	2,455	-	46,434	5,684	64.01	363,842	168	3.67	617	-	-	-	-	364,459
2019	125.0	38,189	1,956	-	38,515	11,290	58.38	659,060	321	3.67	1,179	-	-	-	-	660,239
2020	126.3	29,055	1,470	-	29,300	8,630	58.55	505,300	242	3.67	889	-	-	-	-	506,188
2021	123.1	22,101	1,126	-	22,288	6,580	59.80	393,497	185	3.67	679	-	-	-	-	394,176
2022	119.2	17,100	873	-	17,246	5,127	63.77	326,936	143	3.67	526	-	-	-	-	327,462
2023	86.8	11,548	705	-	11,666	3,904	65.15	254,341	116	3.67	425	-	-	-	-	254,766
2024	77.7	8,952	576	-	9,048	3,072	66.56	204,506	95	3.67	348	-	-	-	-	204,855
2025	64.5	6,602	477	-	6,682	2,225	67.76	150,733	78	3.67	287	-	-	-	-	151,020
2026	51.1	4,226	398	-	4,293	1,376	68.85	94,771	65	3.67	240	-	-	-	-	95,011
2027	20.0	1,342	336	-	1,398	359	70.58	25,354	55	3.67	203	-	-	-	-	25,557
2028	14.5	749	26	-	754	213	72.34	15,410	4	3.67	16	-	-	-	-	15,425
2029	12.0	537	-	-	537	154	74.08	11,406	-	-	-	-	-	-	-	11,406
2030	8.2	307	-	-	307	82	75.40	6,203	-	-	-	-	-	-	-	6,203
2031	3.3	131	-	-	131	33	76.04	2,491	-	-	-	-	-	-	-	2,491
2032	2.0	71	-	-	71	18	77.37	1,375	-	-	-	-	-	-	-	1,375
Rem.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**-**	**-**	**-**	**-**	**-**	**48,747**	**61.85**	**3,015,224**	**1,474**	**3.67**	**5,409**	**-**	**-**	**-**	**-**	**3,020,633**
@10.0%	-	-	-	-	-	-	47.83	2,331,615	-	2.80	4,129	-	-	-	-	2,335,744

Year	Royalties State Royalty Oil M$	Royalties State Royalty Gas M$	Royalties HPS M$	Royalties Other Roy. & Burdens M$	Royalties Total M$	Royalties Total %	Net Volumes Oil Mbbl	Net Volumes Gas MMcf	Net Volumes Liquids Mbbl	Net Interest Revenue M$	Other Revenue M$
2018 (5)	31,421	39	35,775	6,115	73,350	20.1	4,542	157	-	291,108	3,234
2019	56,761	75	58,673	10,029	125,539	19.0	9,148	301	-	534,700	6,975
2020	43,708	57	45,223	6,927	95,915	18.9	6,999	227	-	410,274	5,200
2021	33,999	43	36,963	4,949	75,955	19.3	5,315	173	-	318,221	3,812
2022	28,408	34	33,613	3,792	65,847	20.1	4,098	134	-	261,615	2,971
2023	22,147	27	27,770	2,472	52,417	20.6	3,101	108	-	202,349	2,318
2024	18,052	22	22,648	1,589	42,311	20.7	2,438	89	-	162,544	1,963
2025	13,584	18	15,929	1,016	30,548	20.2	1,775	73	-	120,473	1,509
2026	8,947	15	8,581	568	18,112	19.1	1,114	61	-	76,900	1,059
2027	2,476	13	389	294	3,172	12.4	314	52	-	22,385	350
2028	1,569	1	-	215	1,785	11.6	188	4	-	13,641	189
2029	1,217	-	-	146	1,363	11.9	136	-	-	10,043	121
2030	521	-	-	100	622	10.0	74	-	-	5,582	78
2031	199	-	-	63	263	10.5	29	-	-	2,229	14
2032	110	-	-	37	146	10.7	16	-	-	1,228	6
Rem.	-	-	-	-	-	-	-	-	-	-	-
Total	**263,119**	**346**	**285,566**	**38,312**	**587,344**	**19.4**	**39,288**	**1,379**	**-**	**2,433,289**	**29,801**
@10.0%	202,667	264	220,846	30,965	454,742	19.5	-	-	-	1,881,002	23,021

Year	Operating Costs M$	Operating Costs $/BOE	Abd. & Recl. Costs M$	Net Op. Income M$	Capital Costs M$	Future Net Revenue Before Tax Annual M$	Future Net Revenue Before Tax Cum. M$	Future Net Revenue Before Tax NPV @10.0% M$	Taxes Payable M$	After Tax Annual M$	After Tax NPV @10.0% M$
2018 (5)	65,903	11.54	-	228,439	7,788	220,651	220,651	216,395	51,992	168,659	164,828
2019	148,328	13.08	-	393,347	3,864	389,483	610,134	357,924	71,139	318,344	292,712
2020	137,945	15.91	-	277,528	3,724	273,804	883,939	228,692	34,781	239,023	199,708
2021	128,612	19.45	316	193,105	157	192,947	1,076,886	146,594	13,243	179,705	136,562
2022	122,535	23.79	726	141,326	322	141,005	1,217,891	97,394	5,399	135,606	93,676
2023	107,802	27.48	330	96,535	328	96,207	1,314,098	60,417	13,340	82,867	52,065
2024	100,243	32.46	5,636	58,627	116	58,511	1,372,609	33,340	19,532	38,979	22,222
2025	84,781	37.89	2,374	34,827	471	34,356	1,406,965	17,854	10,276	24,080	12,537
2026	59,401	42.82	4,875	13,682	-	13,682	1,420,647	6,521	5,303	8,380	4,027
2027	15,337	41.63	7,660	-261	-	-261	1,420,386	-28	2,138	-2,399	-943
2028	9,428	44.11	6,453	-2,053	-	-2,053	1,418,333	-902	1,348	-3,401	-1,426
2029	7,900	51.31	1,567	697	-	697	1,419,031	250	655	42	18
2030	4,683	56.92	-	976	-	976	1,420,007	316	315	662	215
2031	1,956	59.69	1,564	-1,277	-	-1,277	1,418,730	-387	93	-1,369	-414
2032	1,186	66.74	931	-883	-	-883	1,417,847	-245	15	-898	-249
Rem.	-	-	1,021	-1,021	-	-1,021	-1,021	-243	-	-1,021	-243
Total	**996,039**	**-**	**33,454**	**1,433,597**	**16,770**	**1,416,826**	**-**	**1,163,892**	**229,567**	**1,187,259**	**975,294**
@10.0%	709,733	-	15,109	1,179,181	15,289	1,163,892	-	-	188,598	975,294	-

Product	Remaining Reserves Gross Lease	Remaining Reserves W.I.	Remaining Reserves R.I.	Remaining Reserves Net
Light and Medium Oil (Mbbl)	38,639	34,727	-	27,723
Heavy Oil (Mbbl)	19,831	14,020	-	11,565
Natural Gas (MMcf)	3,275	1,474	-	1,379
Total (MBOE)	**59,017**	**48,993**	**-**	**39,518**

RLI	3.43 yrs
Remaining Life	14.08 yrs
Price Schedule	G180701

Net Present Value - M$	@ 0.0%	@ 5.0%	@ 10.0%	@ 15.0%	@ 20.0%
Before Taxes	1,416,826	1,276,852	1,163,892	1,071,258	994,177
After Taxes	**1,187,259**	**1,070,517**	**975,294**	**896,574**	**830,670**

McDaniel & Associates Consultants Ltd.

Prices: McDaniel Jul 2018
Eff. Date: July 31, 2018
Currency: USD

Gran Tierra Energy Inc.

Table 4

Forecast of Production and Revenue - Company Share
Forecast Prices and Costs as of July 31, 2018
Total Proved Reserves

Total Company

	Property Gross					Crude Oil			Natural Gas			Natural Gas Liquids				
Year	No. Of Wells	Crude Oil bbl/d	Natural Gas Mcf/d	NGL bbl/d	Total BOE/d	Annual Volume Mbbl	Sales Price $/bbl	Sales Revenue M$	Annual Volume MMcf	Sales Price $/Mcf	Sales Revenue M$	Annual Volume Mbbl	Sales Price $/bbl	Sales Revenue M$	Other Revenue M$	Sales Revenue M$
2018 (5)	122.0	48,703	2,455	-	49,112	6,091	64.00	389,819	168	3.67	617	-	-	-	-	390,435
2019	143.1	48,113	1,956	-	48,439	14,637	58.29	853,107	321	3.67	1,179	-	-	-	-	854,286
2020	158.2	43,365	2,610	-	43,800	12,731	58.36	743,010	430	3.67	1,577	-	-	-	-	744,587
2021	158.3	34,560	2,929	-	35,048	9,930	59.56	591,447	481	3.67	1,766	-	-	-	-	593,212
2022	153.8	26,012	1,813	-	26,315	7,547	63.51	479,286	298	3.67	1,093	-	-	-	-	480,378
2023	140.6	19,895	1,247	-	20,103	5,887	64.72	381,028	205	3.67	752	-	-	-	-	381,780
2024	109.0	13,138	915	-	13,291	4,517	66.18	298,937	151	3.67	553	-	-	-	-	299,490
2025	98.0	10,156	701	-	10,272	3,462	67.40	233,360	115	3.67	422	-	-	-	-	233,782
2026	75.3	6,782	554	-	6,875	2,275	68.50	155,854	91	3.67	334	-	-	-	-	156,188
2027	58.1	4,720	36	-	4,726	1,643	70.09	115,179	6	3.67	22	-	-	-	-	115,201
2028	34.3	2,525	-	-	2,525	866	71.57	61,952	-	-	-	-	-	-	-	61,952
2029	16.0	609	-	-	609	177	73.80	13,079	-	-	-	-	-	-	-	13,079
2030	12.0	362	-	-	362	100	75.05	7,488	-	-	-	-	-	-	-	7,488
2031	3.6	145	-	-	145	36	76.07	2,742	-	-	-	-	-	-	-	2,742
2032	2.1	85	-	-	85	20	77.52	1,589	-	-	-	-	-	-	-	1,589
Rem.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**-**	**-**	**-**	**-**	**-**	**69,920**	**61.90**	**4,327,876**	**2,266**	**3.67**	**8,315**	**-**	**-**	**-**	**-**	**4,336,190**
@10.0%	-	-	-	-	-	-	46.48	3,250,187	-	2.76	6,262	-	-	-	-	3,256,449

	Royalties						Net Volumes				
	State Royalty				Total						
Year	Oil M$	Gas M$	HPS M$	Other Roy. & Burdens M$	M$	%	Oil Mbbl	Gas MMcf	Liquids Mbbl	Net Interest Revenue M$	Other Revenue M$
2018 (5)	33,871	39	38,086	5,865	77,862	19.9	4,879	157	-	312,573	3,656
2019	75,495	75	72,866	11,022	159,459	18.7	11,912	301	-	694,827	10,417
2020	65,924	101	61,034	10,821	137,880	18.5	10,380	402	-	606,707	8,987
2021	51,414	113	50,450	8,007	109,984	18.5	8,092	450	-	483,229	6,742
2022	41,300	70	47,534	5,879	94,782	19.7	6,060	279	-	385,596	5,339
2023	32,477	48	39,119	4,191	75,836	19.9	4,719	192	-	305,944	4,917
2024	25,460	35	32,013	3,078	60,586	20.2	3,604	141	-	238,904	3,019
2025	19,901	27	24,725	2,215	46,868	20.0	2,768	108	-	186,914	2,444
2026	13,569	21	15,223	1,502	30,316	19.4	1,833	85	-	125,872	1,713
2027	9,804	1	11,464	964	22,233	19.3	1,326	6	-	92,968	1,187
2028	4,911	-	5,922	311	11,144	18.0	710	-	-	50,807	701
2029	1,351	-	-	157	1,508	11.5	157	-	-	11,570	123
2030	624	-	-	110	734	9.8	90	-	-	6,753	79
2031	219	-	-	72	291	10.6	32	-	-	2,451	16
2032	127	-	-	46	173	10.9	18	-	-	1,416	8
Rem.	-	-	-	-	-	-	-	-	-	-	-
Total	**376,448**	**532**	**398,436**	**54,242**	**829,658**	**19.1**	**56,581**	**2,121**	**-**	**3,506,532**	**49,349**
@10.0%	283,483	401	296,286	41,939	622,109	19.1	-	-	-	2,634,340	37,192

	Operating Costs					Future Net Revenue Before Tax				After Tax	
Year	M$	$/BOE	Abd. & Recl. Costs M$	Net Op. Income M$	Capital Costs M$	Annual M$	Cum. M$	NPV @10.0% M$	Taxes Payable M$	Annual M$	NPV @10.0% M$
2018 (5)	69,143	11.30	4,320	242,766	100,016	142,749	142,749	139,770	55,827	91,243	84,399
2019	171,260	11.66	302	533,682	121,479	412,203	554,952	377,513	106,402	305,800	279,975
2020	168,753	13.18	-	446,942	70,930	376,012	930,964	313,190	71,994	304,018	253,194
2021	159,524	15.94	316	330,132	157	329,975	1,260,939	250,705	34,789	295,186	224,349
2022	148,801	19.59	726	241,409	322	241,087	1,502,026	166,504	8,433	232,654	160,696
2023	140,405	23.71	430	170,026	328	169,698	1,671,724	106,541	40,993	128,705	80,875
2024	123,991	27.30	5,213	112,719	116	112,603	1,784,327	64,309	31,434	81,168	46,417
2025	112,107	32.20	2,374	74,878	471	74,407	1,858,733	38,625	20,786	53,620	27,869
2026	80,008	34.93	5,937	41,640	-	41,640	1,900,373	19,748	12,735	28,905	13,757
2027	68,740	41.80	3,805	21,609	-	21,609	1,921,983	9,287	5,309	16,300	7,017
2028	42,346	48.92	6,123	3,039	-	3,039	1,925,022	1,243	1,605	1,434	618
2029	8,849	49.94	13,658	-10,814	-	-10,814	1,914,208	-3,808	694	-11,508	-4,053
2030	5,588	56.01	-	1,245	-	1,245	1,915,453	403	403	842	273
2031	2,023	56.12	1,950	-1,506	-	-1,506	1,913,947	-450	144	-1,650	-493
2032	1,276	62.24	2,096	-1,948	-	-1,948	1,911,999	-541	48	-1,995	-554
Rem.	-	-	1,242	-1,242	-	-1,242	-1,242	-295	-	-1,242	-295
Total	**1,302,813**	**-**	**48,492**	**2,204,576**	**293,819**	**1,910,757**	**-**	**1,482,741**	**391,596**	**1,523,480**	**1,174,045**
@10.0%	895,145	-	22,649	1,753,738	270,997	1,482,741	-	-	308,696	1,174,045	-

	Remaining Reserves			
Product	Gross Lease	W.I.	R.I.	Net
Light and Medium Oil (Mbbl)	48,683	42,912	-	34,267
Heavy Oil (Mbbl)	35,603	27,007	-	22,314
Natural Gas (MMcf)	5,035	2,266	-	2,121
Total (MBOE)	**85,126**	**70,297**	**-**	**56,935**

	Net Present Value - M$				
	@ 0.0%	@ 5.0%	@ 10.0%	@ 15.0%	@ 20.0%
Before Taxes	1,910,757	1,671,460	1,482,741	1,331,257	1,207,694
After Taxes	**1,523,480**	**1,326,936**	**1,174,045**	**1,050,537**	**949,315**

RLI 4.95 yrs
Remaining Life 14.17 yrs
Price Schedule G180701

Gran Tierra Energy Inc.

Forecast of Production and Revenue - Company Share
Forecast Prices and Costs as of July 31, 2018
Total Proved + Probable Reserves

Total Company

	Property Gross					Crude Oil			Natural Gas			Natural Gas Liquids				
Year	No. Of Wells	Crude Oil bbl/d	Natural Gas Mcf/d	NGL bbl/d	Total BOE/d	Annual Volume Mbbl	Sales Price $/bbl	Sales Revenue M$	Annual Volume MMcf	Sales Price $/Mcf	Sales Revenue M$	Annual Volume Mbbl	Sales Price $/bbl	Sales Revenue M$	Other Revenue M$	Sales Revenue M$
2018 (5)	123.0	50,732	2,492	0	51,148	6,354	63.97	406,464	171	3.67	626	0	67.49	0	-	407,090
2019	145.4	55,546	2,050	0	55,887	16,994	58.25	989,895	337	3.67	1,236	0	63.86	0	-	991,131
2020	172.6	60,696	2,752	0	61,155	17,522	58.25	1,020,711	453	3.67	1,664	0	65.92	0	-	1,022,375
2021	188.2	60,693	3,580	0	61,290	16,838	59.37	999,631	588	3.67	2,158	0	69.14	0	-	1,001,789
2022	187.6	51,141	2,726	-	51,596	14,359	63.27	908,420	448	3.67	1,643	-	-	-	-	910,063
2023	181.7	40,606	2,106	-	40,957	11,863	64.42	764,168	346	3.67	1,269	-	-	-	-	765,437
2024	151.0	29,434	1,646	-	29,708	9,724	65.86	640,413	271	3.67	995	-	-	-	-	641,408
2025	139.7	23,933	1,335	-	24,156	8,162	67.12	547,837	219	3.67	804	-	-	-	-	548,641
2026	126.3	20,078	1,101	-	20,261	6,852	68.46	469,078	181	3.67	664	-	-	-	-	469,742
2027	122.0	17,045	922	-	17,199	5,826	69.88	407,166	151	3.67	556	-	-	-	-	407,721
2028	111.9	14,092	782	-	14,222	4,831	71.14	343,672	129	3.67	472	-	-	-	-	344,144
2029	93.5	11,054	670	-	11,165	3,762	72.34	272,136	110	3.67	404	-	-	-	-	272,540
2030	88.1	9,471	580	-	9,568	3,235	73.77	238,630	95	3.67	350	-	-	-	-	238,980
2031	76.8	7,693	426	-	7,764	2,634	75.19	198,044	70	3.67	257	-	-	-	-	198,301
2032	53.2	5,362	-	-	5,362	1,916	76.50	146,614	-	-	-	-	-	-	-	146,614
Rem.	21.9	1,953.7	-	-	1,953.7	5,649	81.20	458,718	-	-	-	-	-	-	-	458,718
Total	-	-	-	-	-	**136,521**	**64.54**	**8,811,595**	**3,569**	**3.67**	**13,098**	**0**	**65.95**	**1**	-	**8,824,694**
@10.0%	-	-	-	-	-	-	40.73	5,560,603	-	2.45	8,740	-	57.96	1	-	5,569,344

	Royalties						Net Volumes				
	State Royalty				Total						
Year	Oil M$	Gas M$	HPS M$	Other Roy. & Burdens M$	M$	%	Oil Mbbl	Gas MMcf	Liquids Mbbl	Net Interest Revenue M$	Other Revenue M$
2018 (5)	35,461	40	39,356	6,432	81,289	20.0	5,087	160	0	325,800	3,794
2019	89,427	79	84,030	13,323	186,859	18.9	13,798	315	0	804,272	12,091
2020	93,028	106	80,663	15,202	188,999	18.5	14,291	424	0	833,375	14,175
2021	89,419	138	81,622	15,656	186,835	18.7	13,706	550	0	814,954	14,248
2022	79,973	105	82,963	13,608	176,649	19.4	11,578	419	-	733,414	11,812
2023	66,202	81	71,591	10,657	148,532	19.4	9,566	324	-	616,905	9,424
2024	54,682	64	62,995	8,446	126,187	19.7	7,814	254	-	515,221	6,906
2025	46,284	51	57,556	6,866	110,757	20.2	6,514	205	-	437,884	5,639
2026	39,122	42	55,552	5,708	100,424	21.4	5,384	169	-	369,318	4,973
2027	33,643	36	49,330	4,682	87,692	21.5	4,570	142	-	320,029	4,415
2028	28,202	30	42,046	3,758	74,037	21.5	3,789	120	-	270,108	3,917
2029	22,125	26	32,922	2,973	58,046	21.3	2,958	103	-	214,494	3,320
2030	19,244	22	29,643	2,525	51,435	21.5	2,536	89	-	187,545	2,962
2031	14,852	16	25,355	2,118	42,342	21.4	2,069	66	-	155,959	2,635
2032	10,716	-	17,907	1,389	30,012	20.5	1,523	-	-	116,602	1,747
Rem.	31,267	-	58,824	258	90,349	19.7	4,537	-	-	368,370	6,122
Total	**753,648**	**838**	**872,355**	**113,602**	**1,740,443**	**19.7**	**109,720**	**3,341**	**0**	**7,084,251**	**108,179**
@10.0%	485,200	559	521,485	76,550	1,083,794	19.5	-	-	-	4,485,550	68,700

	Operating Costs					Future Net Revenue Before Tax				After Tax	
Year	M$	$/BOE	Abd. & Recl. Costs M$	Net Op. Income M$	Capital Costs M$	Annual M$	Cum. M$	NPV @10.0% M$	Taxes Payable M$	Annual M$	NPV @10.0% M$
2018 (5)	70,800	11.09	2,700	256,095	111,826	144,268	144,268	141,183	58,557	88,412	83,105
2019	187,625	11.00	-	628,739	158,670	470,069	614,337	429,789	135,381	334,688	305,687
2020	202,199	11.49	-	645,352	175,086	470,265	1,084,603	390,155	126,759	343,506	284,520
2021	209,952	12.40	-	619,250	48,490	570,761	1,655,363	432,161	112,851	457,910	346,667
2022	201,215	13.94	318	543,692	322	543,370	2,198,733	374,810	88,076	455,294	314,151
2023	191,073	16.03	489	434,767	328	434,439	2,633,173	272,485	113,165	321,274	201,632
2024	176,331	18.05	2,102	343,694	284	343,411	2,976,583	195,868	93,177	250,234	142,832
2025	167,152	20.39	414	275,958	471	275,487	3,252,070	142,799	79,841	195,646	101,486
2026	155,690	22.62	3,002	215,598	-	215,598	3,467,668	101,626	63,423	152,175	71,791
2027	150,246	25.68	1,873	172,325	-	172,325	3,639,993	73,805	49,917	122,408	52,458
2028	135,292	27.88	1,173	137,560	-	137,560	3,777,553	53,582	41,194	96,366	37,567
2029	107,220	28.36	7,120	103,473	-	103,473	3,881,026	36,665	34,271	69,202	24,553
2030	103,618	31.88	778	86,110	-	86,110	3,967,137	27,724	27,328	58,782	18,944
2031	91,436	34.56	803	66,355	-	66,355	4,033,492	19,419	21,334	45,021	13,187
2032	66,865	34.89	10,712	40,772	-	40,772	4,074,264	10,858	16,344	24,428	6,519
Rem.	269,435	-	25,205	79,852	-	79,852	79,852	18,236	31,966	47,885	11,232
Total	**2,486,150**	-	**56,688**	**4,649,592**	**495,477**	**4,154,116**	-	**2,721,165**	**1,093,583**	**3,063,232**	**2,016,331**
@10.0%	1,373,880	-	17,621	3,162,749	441,584	2,721,165	-	-	704,834	2,016,331	-

	Remaining Reserves			
Product	Gross Lease	W.I.	R.I.	Net
Light and Medium Oil (Mbbl)	82,162	71,600	-	57,153
Heavy Oil (Mbbl)	79,869	64,922	-	52,567
Natural Gas (MMcf)	7,931	3,569	-	3,341
Natural Gas Liquids (Mbbl)	0	0	-	0
Total (MBOE)	**163,353**	**137,116**	-	**110,277**

RLI	9.47	yrs
Remaining Life	21.83	yrs
Price Schedule	G180701	

	Net Present Value - M$				
	@ 0.0%	@ 5.0%	@ 10.0%	@ 15.0%	@ 20.0%
Before Taxes	4,154,116	3,305,562	2,721,165	2,300,644	1,986,860
After Taxes	**3,063,232**	**2,445,296**	**2,016,331**	**1,704,656**	**1,470,314**

Prices: McDaniel Jul 2018
Eff. Date: July 31, 2018
Currency: USD

Gran Tierra Energy Inc.

Table 6

Forecast of Production and Revenue - Company Share
Forecast Prices and Costs as of July 31, 2018
Total Proved + Probable + Possible Reserves

Total Company

	Property Gross					Crude Oil			Natural Gas			Natural Gas Liquids				
Year	No. Of Wells	Crude Oil bbl/d	Natural Gas Mcf/d	NGL bbl/d	Total BOE/d	Annual Volume Mbbl	Sales Price $/bbl	Sales Revenue M$	Annual Volume MMcf	Sales Price $/Mcf	Sales Revenue M$	Annual Volume Mbbl	Sales Price $/bbl	Sales Revenue M$	Other Revenue M$	Sales Revenue M$
2018 (5)	123.0	51,796	2,526	-	52,217	6,483	63.98	414,830	173	3.67	634	-	-	-	-	415,465
2019	147.0	61,439	2,137	-	61,795	18,881	58.25	1,099,767	351	3.67	1,288	-	-	-	-	1,101,055
2020	177.5	71,869	2,880	-	72,349	20,939	58.25	1,219,720	474	3.67	1,741	-	-	-	-	1,221,461
2021	206.4	77,991	4,695	-	78,774	21,742	59.33	1,290,013	771	3.67	2,830	-	-	-	-	1,292,843
2022	220.8	74,148	4,102	-	74,831	20,965	63.20	1,324,959	674	3.67	2,472	-	-	-	-	1,327,431
2023	221.3	63,276	3,268	-	63,820	18,232	64.33	1,172,811	537	3.67	1,970	-	-	-	-	1,174,781
2024	192.3	47,851	2,658	-	48,294	15,288	65.72	1,004,789	438	3.67	1,607	-	-	-	-	1,006,395
2025	172.0	38,610	2,200	-	38,976	13,013	67.01	872,067	361	3.67	1,326	-	-	-	-	873,393
2026	171.2	33,655	1,838	-	33,961	11,351	68.36	776,020	302	3.67	1,108	-	-	-	-	777,127
2027	165.4	29,136	1,543	-	29,393	9,845	69.80	687,173	253	3.67	930	-	-	-	-	688,103
2028	156.2	25,067	1,327	-	25,288	8,508	71.14	605,238	219	3.67	802	-	-	-	-	606,040
2029	148.5	21,826	1,153	-	22,018	7,405	72.57	537,359	189	3.67	695	-	-	-	-	538,054
2030	140.0	19,020	1,010	-	19,188	6,471	74.00	478,917	166	3.67	609	-	-	-	-	479,525
2031	134.3	16,703	892	-	16,852	5,693	75.52	429,913	146	3.67	538	-	-	-	-	430,451
2032	129.8	14,728	793	-	14,861	5,037	77.04	388,014	131	3.67	479	-	-	-	-	388,493
Rem.	55.6	5,395.8	24.2	-	5,399.9	19,144	83.04	1,589,785	40	3.67	146	-	-	-	-	1,589,931
Total	**-**	**-**	**-**	**-**	**-**	**208,998**	**66.47**	**13,891,374**	**5,225**	**3.67**	**19,175**	**-**	**-**	**-**	**-**	**13,910,550**
@10.0%	-	-	-	-	-	-	37.53	7,843,883	-	2.28	11,923	-	-	-	-	7,855,806

	Royalties						Net Volumes				
	State Royalty				Total					Net	
Year	Oil M$	Gas M$	HPS M$	Other Roy. & Burdens M$	M$	%	Oil Mbbl	Gas MMcf	Liquids Mbbl	Interest Revenue M$	Other Revenue M$
2018 (5)	36,251	41	40,164	6,679	83,134	20.0	5,189	162	-	332,331	3,862
2019	101,298	82	93,623	14,766	209,770	19.1	15,293	329	-	891,285	13,442
2020	114,182	111	97,129	18,300	229,723	18.8	17,011	444	-	991,738	17,159
2021	118,596	181	103,801	20,664	243,242	18.8	17,660	722	-	1,049,601	18,978
2022	120,116	158	115,332	23,598	259,204	19.5	16,881	631	-	1,068,227	17,914
2023	104,823	126	125,279	20,029	250,256	21.3	14,345	502	-	924,525	14,424
2024	88,563	103	117,102	16,583	222,350	22.1	11,903	410	-	784,046	10,329
2025	75,704	85	109,694	13,948	199,431	22.8	10,034	338	-	673,962	8,678
2026	66,646	71	100,825	11,963	179,506	23.1	8,723	282	-	597,621	7,939
2027	58,437	60	90,911	10,252	159,660	23.2	7,555	237	-	528,443	7,193
2028	50,897	51	81,374	8,840	141,163	23.3	6,522	205	-	464,878	6,516
2029	44,809	44	73,385	7,622	125,860	23.4	5,668	177	-	412,194	5,934
2030	39,634	39	66,727	6,572	112,972	23.6	4,943	155	-	366,553	5,399
2031	35,284	34	60,951	5,678	101,947	23.7	4,341	137	-	328,503	4,973
2032	31,549	31	55,884	4,933	92,396	23.8	3,836	122	-	296,096	4,626
Rem.	118,981	9	233,680	12,195	364,865	22.9	14,737	37	-	1,225,066	22,357
Total	**1,205,770**	**1,227**	**1,565,862**	**202,622**	**2,975,481**	**21.4**	**164,641**	**4,890**	**-**	**10,935,069**	**169,723**
@10.0%	697,376	763	807,918	120,314	1,626,371	20.7	-	-	-	6,229,435	96,563

	Operating Costs		Abd. & Recl. Costs	Net Op. Income	Capital Costs	Future Net Revenue Before Tax			Taxes Payable	After Tax	
Year	M$	$/BOE	M$	M$	M$	Annual M$	Cum. M$	NPV @10.0% M$	M$	Annual M$	NPV @10.0% M$
2018 (5)	71,406	10.96	360	264,426	113,746	150,681	150,681	147,417	60,464	90,577	87,447
2019	198,865	10.50	-	705,863	168,053	537,810	688,490	491,034	160,831	376,979	343,603
2020	224,683	10.69	-	784,214	214,020	570,194	1,258,684	473,326	168,121	402,073	333,222
2021	244,696	11.19	-	823,883	120,259	703,625	1,962,309	531,934	168,670	534,955	404,151
2022	247,298	11.73	-	838,843	45,323	793,520	2,755,829	546,154	164,331	629,189	432,976
2023	238,194	13.00	658	700,096	328	699,768	3,455,597	438,867	184,727	515,041	323,208
2024	220,911	14.38	166	573,297	284	573,014	4,028,611	326,739	154,904	418,110	238,570
2025	208,728	15.97	2,190	471,722	642	471,080	4,499,691	244,074	134,431	336,649	174,513
2026	203,368	17.84	-	402,192	-	402,192	4,901,883	189,439	117,506	284,686	134,164
2027	195,789	19.80	514	339,333	-	339,333	5,241,216	145,304	100,286	239,047	102,417
2028	186,525	21.83	2,747	282,122	-	282,122	5,523,338	109,841	84,981	197,141	76,803
2029	180,562	24.28	2,325	235,240	-	235,240	5,758,578	83,255	72,261	162,979	57,717
2030	174,148	26.80	943	196,861	-	196,861	5,955,439	63,342	61,023	135,838	43,736
2031	169,302	29.61	1,568	162,608	-	162,608	6,118,046	47,557	50,812	111,796	32,715
2032	165,913	32.80	1,562	133,248	-	133,248	6,251,294	35,438	41,899	91,348	24,312
Rem.	1,001,059	-	55,537	190,827	-	190,827	190,827	46,103	136,436	54,391	18,988
Total	**3,931,447**	**-**	**68,570**	**7,104,776**	**662,654**	**6,442,121**	**-**	**3,919,823**	**1,861,684**	**4,580,798**	**2,828,542**
@10.0%	1,821,267	-	14,061	4,490,669	570,847	3,919,823	-	-	1,091,281	2,828,542	-

	Remaining Reserves			
Product	Gross Lease	W.I.	R.I.	Net
Light and Medium Oil (Mbbl)	130,026	112,740	-	88,501
Heavy Oil (Mbbl)	115,006	96,258	-	76,140
Natural Gas (MMcf)	11,611	5,225	-	4,890
Total (MBOE)	**246,967**	**209,869**	**-**	**165,456**

RLI	14.24 yrs
Remaining Life	24.08 yrs
Price Schedule	G180701

	Net Present Value - M$				
	@ 0.0%	@ 5.0%	@ 10.0%	@ 15.0%	@ 20.0%
Before Taxes	6,442,121	4,925,836	3,919,823	3,220,937	2,715,696
After Taxes	**4,580,798**	**3,537,831**	**2,828,542**	**2,327,902**	**1,962,149**

McDaniel & Associates Consultants Ltd.