GRAN TIERRA ENERGY INC.
Form 10-Q
November 01, 2018

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2018

or

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________

Commission file number 001-34018

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

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

900, 520 - 3 Avenue SW
Calgary, Alberta Canada T2P 0R3
(Address of principal executive offices, including zip code)
(403) 265-3221
(Registrant’s telephone number, including area code)

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).
Yes ý No o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of large accelerated filer, accelerated filer, smaller reporting company, and emerging growth company in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o	Smaller reporting company o
	Emerging growth company o

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

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

On October 30, 2018, 391,347,284 shares of the registrant's Common Stock, $0.001 par value, were outstanding.

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Gran Tierra Energy Inc.

Quarterly Report on Form 10-Q

Quarterly Period Ended September 30, 2018

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CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical facts included in this Quarterly Report on Form 10-Q regarding our financial position, estimated quantities and net present values of reserves, business strategy, plans and objectives of our management for future operations, covenant compliance, capital spending plans and those statements preceded by, followed by or that otherwise include the words “believe”, “expect”, “anticipate”, “intend”, “estimate”, “project”, “target”, “goal”, “plan”, “budget”, “objective”, “could”, “should”, or similar expre variations on these expressions are forward-looking statements. We can give no assurances that the assumptions upon which the forward-looking statements are based will prove to be correct or that, even if correct, intervening circumstances will not occur to cause actual results to be different than expected. Because forward-looking statements are subject to risks and uncertainties, actual results may differ materially from those expressed or implied by the forward-looking statements. There are a number of risks, uncertainties and other important factors that could cause our actual results to differ materially from the forward-looking statements, including, but not limited to, sustained or future declines in commodity prices; potential future impairments and reductions in proved reserve quantities and value; our operations are located in South America, and unexpected problems can arise due to guerilla activity; technical difficulties and operational difficulties may arise which impact the production, transport or sale of our products; geographic, political and weather conditions can impact the production, transport or sale of our products; the risk that current global economic and credit conditions may impact oil prices and oil consumption more than we currently predict; our ability to execute business plans; the risk that unexpected delays and difficulties in developing currently owned properties may occur; the timely receipt of regulatory or other required approvals for our operating activities; the failure of exploratory drilling to result in commercial wells; unexpected delays due to the limited availability of drilling equipment and personnel; the risk that current global economic and credit market conditions may impact oil prices and oil consumption more than we currently predict, which could cause us to further modify our strategy and capital spending program; those factors set out in Part I, Item 1A “Risk Factors” in our 2017 Annual Report on Form 10-K and in our other filings with the Securities and Exchange Commission (“SEC”). The information included herein is given as of the filing date of this Quarterly Report on Form 10-Q with the SEC and, except as otherwise required by the federal securities laws, we disclaim any obligation or undertaking to publicly release any updates or revisions to any forward-looking statement contained in this Quarterly Report on Form 10-Q to reflect any change in our expectations with regard thereto or any change in events, conditions or circumstances on which any forward-looking statement is based.

GLOSSARY OF OIL AND GAS TERMS

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

bbl	barrel	BOE	barrels of oil equivalent
bopd	barrels of oil per day	BOEPD	barrels of oil equivalent per day
Mcf	thousand cubic feet	NAR	net after royalty

Sales volumes represent production NAR adjusted for inventory changes. Our oil and gas reserves are reported NAR. Our production is also reported NAR, except as otherwise specifically noted as "working interest production before royalties." Natural gas liquids ("NGLs") volumes are converted to BOE on a one-to-one basis with oil. Gas volumes are converted to BOE at the rate of 6 Mcf of gas per bbl of oil, based upon the approximate relative energy content of gas and oil. The rate is not necessarily indicative of the relationship between oil and gas prices. 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.

PART I - Financial Information

Item 1. Financial Statements

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
OIL AND NATURAL GAS SALES (Notes 3 and 7)	$175,118	$103,768	$476,792	$294,555
EXPENSES				
Operating	29,511	21,931	78,019	60,547
Workover	13,106	5,390	25,922	17,919
Transportation	7,505	6,038	21,024	19,472
Depletion, depreciation and accretion (Note 3)	51,630	35,279	137,698	93,968
General and administrative (Note 3)	13,811	8,651	37,173	26,876
Severance	1,004	1,164	2,015	1,164
Equity tax	—	—	—	1,224
Foreign exchange (gain) loss	(888)	(1,271)	94	779
Financial instruments (gain) loss (Note 10)	(4,874)	1,675	6,840	(5,211)
Interest expense (Note 5)	7,404	3,989	20,274	10,415
	118,209	82,846	329,059	227,153
LOSS ON SALE	—	—	(292)	(9,076)
INTEREST INCOME	725	301	2,121	954
INCOME BEFORE INCOME TAXES (Note 3)	57,634	21,223	149,562	59,280
INCOME TAX EXPENSE (RECOVERY)				
Current (Note 8)	19,108	4,333	36,224	13,522
Deferred (Note 8)	(36,769)	13,760	(118)	36,664
	(17,661)	18,093	36,106	50,186
NET AND COMPREHENSIVE INCOME	$75,295	$3,130	$113,456	$9,094
NET INCOME PER SHARE				
- BASIC	$0.19	$0.01	$0.29	$0.02
- DILUTED	$0.18	$0.01	$0.28	$0.02
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC (Note 6)	391,209,589	394,771,194	391,185,636	397,439,007
WEIGHTED AVERAGE SHARES OUTSTANDING - DILUTED (Note 6)	427,947,959	394,774,953	427,416,964	397,450,637

(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 September 30, 2018	As at December 31, 2017
ASSETS		
Current Assets		
Cash and cash equivalents (Note 11)	$130,158	$12,326
Restricted cash and cash equivalents (Note 11)	1,228	11,787
Accounts receivable	64,616	45,353
Investment (Note 10)	37,608	25,055
Taxes receivable	70,256	40,831
Other current assets	14,153	9,893
Total Current Assets	318,019	145,245
Oil and Gas Properties (using the full cost method of accounting)		
Proved	804,204	629,081
Unproved	441,275	464,948
Total Oil and Gas Properties	1,245,479	1,094,029
Other capital assets	2,901	5,195
Total Property, Plant and Equipment (Note 3)	1,248,380	1,099,224
Other Long-Term Assets		
Deferred tax assets	58,901	57,310
Investment (Note 10)	17,623	19,147
Other long-term assets (Note 11)	5,133	6,112
Goodwill (Note 3)	102,581	102,581
Total Other Long-Term Assets	184,238	185,150
Total Assets (Note 3)	$1,750,637	$1,429,619
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	$164,885	$126,199
Derivatives (Note 10)	17,688	21,151
Taxes payable	9,759	9,324
Equity compensation award liability (Note 10)	16,534	295
Total Current Liabilities	208,866	156,969
Long-Term Liabilities		
Long-term debt (Notes 5 and 10)	398,989	256,542
Deferred tax liabilities	28,470	28,417
Asset retirement obligation	38,877	31,241
Equity compensation award liability (Note 10)	14,648	11,135
Other long-term liabilities	9,257	8,980
Total Long-Term Liabilities	490,241	336,315
Contingencies (Note 9)		

Shareholders’ Equity		
Common Stock (Note 6) (391,339,489 and 385,191,042 shares of Common Stock and nil and 6,111,665 exchangeable shares, par value $0.001 per share, issued and outstanding as at September 30, 2018, and December 31, 2017, respectively)	10,295	10,295
Additional paid in capital	1,328,983	1,327,244
Deficit	(287,748)	(401,204)
Total Shareholders’ Equity	1,051,530	936,335
Total Liabilities and Shareholders’ Equity	$1,750,637	$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)

	Nine Months Ended September 30,	
	2018	2017
Operating Activities		
Net income	$113,456	$9,094
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation and accretion (Note 3)	137,698	93,968
Deferred tax (recovery) expense	(118)	36,664
Stock-based compensation (Note 6)	20,477	4,935
Amortization of debt issuance costs (Note 5)	2,329	1,868
Cash settlement of restricted share units	(360)	(534)
Unrealized foreign exchange gain	(133)	(304)
Financial instruments loss (gain) (Note 10)	6,840	(5,211)
Cash settlement of financial instruments (Note 10)	(26,169)	1,518
Cash settlement of asset retirement obligation	(456)	(462)
Loss on sale	292	9,076
Net change in assets and liabilities from operating activities (Note 11)	(40,652)	(28,105)
Net cash provided by operating activities	213,204	122,507
Investing Activities		
Additions to property, plant and equipment (Note 3)	(258,551)	(175,719)
Property acquisitions (Note 4)	(20,100)	(30,410)
Net proceeds from sale of Brazil business unit	—	34,481
Changes in non-cash investing working capital	32,638	16,047
Net cash used in investing activities	(246,013)	(155,601)
Financing Activities		
Proceeds from bank debt, net of issuance costs (Note 5)	4,988	115,264
Repayment of bank debt (Note 5)	(153,000)	(85,000)
Proceeds from exercise of stock options (Note 6)	1,408	—
Repurchase of shares of Common Stock (Note 6)	(1,314)	(10,000)
Proceeds from issuance of Senior Notes, net of issuance costs (Note 5)	288,087	—
Net cash provided by financing activities	140,169	20,264
Foreign exchange loss on cash, cash equivalents and restricted cash and cash equivalents	(402)	(1,060)
Net increase (decrease) in cash, cash equivalents and restricted cash and cash equivalents	106,958	(13,890)
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)	$133,636	$29,377

Supplemental cash flow disclosures (Note 11)

(See notes to the condensed consolidated financial statements)

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

	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Share Capital		
Balance, beginning of period	$10,295	$10,303
Issuance of Common Stock	1	—
Repurchase of Common Stock (Note 6)	(1)	(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)	1,407	—
Stock-based compensation (Note 6)	1,645	1,903
Repurchase of Common Stock (Note 6)	(1,313)	(9,996)
Balance, end of period	1,328,983	1,334,563
Deficit		
Balance, beginning of period	(401,204)	(493,972)
Net income	113,456	9,094
Cumulative adjustment for accounting change related to tax reorganizations	—	124,476
Balance, end of period	(287,748)	(360,402)
Total Shareholders' Equity	$1,051,530	$984,460

(See notes to the condensed consolidated financial statements)

Gran Tierra Energy Inc.
Notes to the Condensed Consolidated Financial Statements (Unaudited)
(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.

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 are the same as the effective date and transition requirements in ASU 2016-02. The Company is planning to adopt ASU 2018-01 upon transition to ASU 2016-02 "Leases".

The Company has completed an assessment of its contract inventory, identified contracts which meet the definition of a lease and is currently determining the value of right-of-use lease assets and lease liabilities and transition adjustments. The Company expects to use practical expedients available for land easements and short-term leases and will apply the guidance of ASU 2016-02 using a modified retrospective transition approach.

Fair Value Measurements

In August 2018, the FASB issued ASU 2018-13, "Changes to the Disclosure Requirements for Fair Value Measurement". ASU 2018-13 will modify certain fair value measurements disclosure requirements. ASU 2018-13 will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2019. The disclosure amendments on changes in unrealized gains and losses, and disclosure requirements for significant unobservable inputs used to develop Level 3 fair value measurements, should be applied prospectively. All other amendments in ASU 2018-13 should be applied retrospectively. Early adoption is permitted. The application of ASU 2018-13 will not impact the Company's consolidated financial position, results of operations or cash flows.

Intangibles - Goodwill and Other - Internal-use Software

In August 2018, the FASB issued ASU 2018-15, "Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract". ASU 2018-15 clarifies requirements for capitalization of software development costs and requires that a hosting arrangement that is a service contract to be capitalized and expensed over the term of the hosting arrangement.

ASU 2018-15 will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2019. The provisions of this amendment should be applied retrospectively or prospectively to all implementation costs incurred after the date of adoption. 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. 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:

	Three Months Ended September 30, 2018		
(Thousands of U.S. Dollars)	Colombia	All Other	Total
Oil and natural gas sales	$175,118	$—	$175,118
Depletion, depreciation and accretion	51,416	214	51,630
General and administrative expenses	7,370	6,441	13,811
Income (loss) before income taxes	63,797	(6,163)	57,634
Segment capital expenditures	101,453	10	101,463

	Three Months Ended September 30, 2017		
(Thousands of U.S. Dollars)	Colombia	All Other	Total
Oil and natural gas sales	$103,768	$—	$103,768
Depletion, depreciation and accretion	33,388	1,891	35,279
General and administrative expenses	5,500	3,151	8,651
Income (loss) before income taxes	31,276	(10,053)	21,223
Segment capital expenditures	70,606	1,088	71,694

	Nine Months Ended September 30, 2018		
(Thousands of U.S. Dollars)	Colombia	All Other	Total
Oil and natural gas sales	$476,792	$—	$476,792
Depletion, depreciation and accretion	135,980	1,718	137,698
General and administrative expenses	20,876	16,297	37,173
Income (loss) before income taxes	175,977	(26,415)	149,562
Segment capital expenditures	257,771	780	258,551

	Nine Months Ended September 30, 2017		
(Thousands of U.S. Dollars)	Colombia	All Other	Total
Oil and natural gas sales	$286,137	$8,418	$294,555
Depletion, depreciation and accretion	88,453	5,515	93,968
General and administrative expenses	15,561	11,315	26,876
Income (loss) before income taxes	90,018	(30,738)	59,280
Segment capital expenditures	168,881	6,838	175,719

	As at September 30, 2018		
(Thousands of U.S. Dollars)	Colombia	All Other	Total
Property, plant and equipment	$1,246,979	$1,401	$1,248,380
Goodwill	102,581	—	102,581
All other assets	226,733	172,943	399,676
Total Assets	$1,576,293	$174,344	$1,750,637

	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

4. Property, Plant and Equipment

On August 6, 2018, the Company acquired a working interest ("WI") in the VMM-2 block in the Middle Magdalena Valley Basin for cash consideration of $17.0 million, of which $6.2 million was allocated to proved properties.

On June 20, 2018, the Company acquired the remaining WI in the Alea 1848-A and 1947-C Blocks in the Putumayo Basin for cash consideration of $3.1 million.

Subsequent to September 30, 2018, the Company acquired the remaining 45% WI in the PUT-1 Block in the Putumayo Basin for cash consideration of $28.1 million.

5. Debt and Debt Issuance Costs

The Company's debt at September 30, 2018 and December 31, 2017 was as follows:

(Thousands of U.S. Dollars)	As at September 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	(16,011)	(6,458)
Long-term debt	$398,989	$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 September 30,		Nine Months Ended September 30,	
(Thousands of U.S. Dollars)	2018	2017	2018	2017
Contractual interest and other financing expenses	$6,588	$3,346	$17,945	$8,547
Amortization of debt issuance costs	816	643	2,329	1,868
	$7,404	$3,989	$20,274	$10,415

6. Share Capital

On May 1, 2018, Gran Tierra Exchangeco Inc., a wholly-owned 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 for each exchangeable share, 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	541,394	—	—
Shares repurchased and canceled	(504,612)	—	—
Exchange of exchangeable shares	6,111,665	(4,422,776)	(1,688,889)
Balance, September 30, 2018	391,339,489	—	—

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 nine months ended September 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	3,660,422	182,607	—	2,049,930	2.54
Exercised	—	—	(120,268)	(541,394)	2.60
Forfeited	(618,735)	—	(1,822)	(656,847)	4.69
Expired	—	—	—	(621,854)	6.55
Balance, September 30, 2018	9,173,638	638,375	—	9,190,527	3.20

Stock-based compensation expense for the three and nine months ended September 30, 2018, was $10.3 million and $20.5 million, respectively, and was primarily recorded in general and administrative ("G&A") expenses (three and nine months ended September 30, 2017 - $1.8 million and $4.9 million, respectively).

At September 30, 2018, there was $24.2 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 1.7 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 September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Weighted average number of common and exchangeable shares outstanding	391,209,589	394,771,194	391,185,636	397,439,007
Shares issuable pursuant to stock options	6,509,385	61,325	4,295,964	187,150
Shares assumed to be purchased from proceeds of stock options	(5,585,408)	(57,566)	(3,879,029)	(175,520)
Shares issuable pursuant to convertible notes	35,814,393	—	35,814,393	—
Weighted average number of diluted common and exchangeable shares outstanding	427,947,959	394,774,953	427,416,964	397,450,637

For the three and nine months ended September 30, 2018, 3,198,865 and 5,436,667 options, respectively, (three and nine months ended September 30, 2017 - 9,259,811 and 9,744,747 options, respectively), on a weighted average basis, 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 nine months ended September 30, 2018, the numerator used in the computation of diluted earnings per share included net income for the period adjusted for interest after tax on convertible debentures and amortization of debt issuance costs of $1.7 million and $5.2 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 nine months ended September 30, 2018, 100% (three and nine months ended September 30, 2017 - 100%) of the Company's revenue resulted from oil sales. During the three and nine months ended September 30, 2018, quality and transportation discounts were 13% and 14% respectively, of the ICE Brent price (three and nine months ended September 30, 2017 - 21% and 22%, respectively). During the three and nine months ended September 30, 2018, the Company's production was sold primarily to two major customers in Colombia (three and nine months ended September 30, 2017 - three).

As at September 30, 2018, accounts receivable included $8.9 million of accrued sales revenue related to September 2018 production (December 31, 2017 - $11.1 million related to December 31, 2017 production).

8. Taxes

The Company's effective tax rate was 24% in the nine months ended September 30, 2018, compared with 85% in the comparative period in 2017. Current income tax expense was higher in the nine months ended September 30, 2018, compared with the corresponding period in 2017, primarily as a result of higher taxable income in Colombia. The deferred income tax recovery of $0.1 million for the nine months ended September 30, 2018 was primarily due to the impact of the release of a portion of the valuation allowance in Colombia, partially offset by the excess tax depreciation compared with accounting depreciation in Colombia.

For the nine months ended September 30, 2018, the difference between the effective tax rate of 24% and the 21% U.S. statutory rate was primarily due to the impact of foreign taxes, which was partially offset by a decrease in the valuation allowance and other permanent differences.

For the comparative period in 2017, the 85% effective tax rate differed from the U.S. statutory rate of 35% primarily due to the impact of foreign taxes and an increase in the valuation allowance, which were partially offset by other permanent differences.

The Tax Cuts and Jobs Act (the "Act") was enacted in the US on December 22, 2017. The Act reduced the US federal corporate income tax rate to 21% from 35%, required companies to pay a one-time transition tax on earnings of certain foreign subsidiaries that were previously tax deferred and created new taxes on certain foreign-sourced earnings. In 2017, the Company recorded provisional amounts for the enactment-date effects of the Act that included adjusting deferred tax assets (before valuation allowance), by applying the guidance in SAB 118, because it had not yet completed its enactment-date accounting for these effects. In the period ended September 30, 2018, the Company filed its US Federal 2017 tax return, whereby the provisional amounts recorded in 2017 were finalized and closed. The changes to the 2017 enactment-date provisional amounts resulted in a $9.4 million increased Foreign Tax Credit carryover balance, which was fully offset by a corresponding increase in the related valuation allowance.

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 $53.7 million as at September 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 September 30, 2018, the Company had provided letters of credit and other credit support totaling $78.3 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 September 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 from Canadian public markets, including the TSX Venture Exchange and alternative trading platforms, at September 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 September 30, 2018, and December 31, 2017, was as follows:

(Thousands of U.S. Dollars)	As at September 30, 2018	As at December 31, 2017
Investment in PetroTal shares - current and long-term	$ 55,231	$ 44,202
Foreign currency derivative asset	100	302
	$ 55,331	$ 44,504
Commodity price derivative liability	$ 17,688	$ 21,151
Equity compensation award liability - current and long-term	31,182	11,430
	$ 48,870	$ 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 September 30,		Nine Months Ended September 30,	
(Thousands of U.S. Dollars)	2018	2017	2018	2017
Commodity price derivative loss (gain)	$929	$2,489	$20,384	$(3,759)
Foreign currency derivatives loss (gain)	525	(814)	(1,499)	(1,452)
Investment gain	(6,328)	—	(12,045)	—
Financial instruments (gain) loss	$(4,874)	$1,675	$6,840	$(5,211)

Investment gain for the three and nine months ended September 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 nine months ended September 30, 2018, this investment gain was unrealized.

Financial instruments not recorded at fair value include the Senior Notes and the Convertible Notes. At September 30, 2018, the carrying amounts of the Senior Notes and the Convertible Notes were $288.9 million and $111.8 million, respectively, which represented the aggregate principal amount less unamortized debt issuance costs, and the fair values were $293.8 million and $153.3 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 September 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)	Nine Months Ended September 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	5,332	56
Unrealized foreign exchange loss	(2,069)	—
Closing balance, investment - long-term	$ 17,623	$ 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 September 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: October 1, to December 31, 2018	5,000	ICE Brent	$ 55.90	n/a
Participating Swaps: October 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 September 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: October 1, 2018 to December 31, 2018	43,500	14,636	COP	3,000	3,107

[(1)] At September 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 September 30,		As at December 31,	
	2018	2017	2017	2016
Cash and cash equivalents	$130,158	$15,125	$12,326	$25,175
Restricted cash and cash equivalents - current	1,228	3,920	11,787	8,322
Restricted cash and cash equivalents - long-term (included in other long-term assets)	2,250	10,332	2,565	9,770
	$133,636	$29,377	$26,678	$43,267

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

	Nine Months Ended September 30,	
(Thousands of U.S. Dollars)	2018	2017
Accounts receivable and other long-term assets	$(35,934)	$8,356
Derivatives	21,645	—
Inventory	(3,375)	(28)
Prepaids	489	3,080
Accounts payable and accrued and other long-term liabilities	5,380	5,951

Taxes receivable and payable	(28,857)	(45,464)
Net changes in assets and liabilities from operating activities	$(40,652)	$(28,105)

The following table provides additional supplemental cash flow disclosures:

	Nine Months Ended September 30,	
(Thousands of U.S. Dollars)	2018	2017
Non-cash investing activities:		
Net liabilities related to property, plant and equipment, end of period	$100,790	$68,018

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Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion of our financial condition and results of operations should be read in conjunction with the "Financial Statements" as set out in Part I, Item 1 of this Quarterly Report on Form 10-Q as well as the "Financial Statements and Supplementary Data" and "Management’s Discussion and Analysis of Financial Condition and Results of Operations" included in Part II, Items 8 and 7, respectively, of our 2017 Annual Report on Form 10-K, filed with the SEC on February 27, 2018. Please see the cautionary language at the beginning of this Quarterly Report on Form 10-Q regarding the identification of and risks relating to forward-looking statements, as well as Part I, Item 1A “Risk Factors” in our 2017 Annual Report on Form 10-K.

Financial and Operational Highlights

Key Highlights for the third quarter of 2018

- Achieved a new company milestone: Colombia working interest production before royalties of 36,170 BOEPD, 11% higher compared with 32,570 BOEPD in the third quarter of 2017. Production increased largely because of production from development activities in the Acordionero Field.
- The quarter's Colombia production also increased 60% from second quarter 2015 when the strategy to refocus Gran Tierra on Colombia began, an annual growth rate of 20%.
- Since acquiring the Acordionero field in the Middle Magdalena Valley ("MMV") in August 2016, we have increased production 299% to a record high average rate during the quarter of 18,885 bopd (14,890 bopd NAR). From the acquisition date of August 23, 2016, until September 30, 2018, the MMV assets have generated $419.8 million in oil and natural gas sales, operating netback of $327.2 million while incurring capital expenditures of $229.8 million
- Production NAR was 28,599 BOEPD, 4% higher than the third quarter of 2017.
- Continued significant exposure to oil price strength with oil representing 100% of our production.
- Oil and natural gas sales volumes were 28,659 BOEPD, 4% higher than the third quarter of 2017. The quarter's increase in oil and gas sales volumes was driven by the production increase (3,600 bopd) and a change in inventory (128 bopd), partially offset by higher royalties (2,516 bopd) due to higher oil prices.
- Net income was $75.3 million compared with $3.1 million in the third quarter of 2017.
- Funds flow from operations[1] increased by 54% to $85.0 million compared with the third quarter of 2017, while the Brent price increased only 46% from the third quarter of 2017.
- Active quarter with capital expenditures of $101.5 million.
- Oil and gas sales per BOE were $66.42, 62% higher than the third quarter of 2017.
- Operating netback[2] per BOE was $47.41, 70% higher than the third quarter of 2017.
- Operating expenses per BOE were $11.19, 29% higher than the third quarter of 2017 as a result of higher power generation costs ($0.74 per bbl) and field operation maintenance activities (0.94 per bbl).
- Workover expenses increased by 133% to $4.97 per bbl compared to the third quarter of 2017. During the quarter, we replaced 9 electric submersible pumps which had an average run life of 243 days.
- Quality and transportation discount was $9.55 per BOE compared with $11.09 per BOE in the third quarter of 2017; this $1.54 per BOE reduction resulted from the optimization of transportation routes and narrowing of differentials.
- Transportation expenses per BOE were $2.85, 19% higher compared with the third quarter of 2017. The increase was due to the increased use of alternative transportation routes, which had higher costs per BOE.
- General and administrative ("G&A") expenses before stock-based compensation per BOE decreased by 49% to $1.40 per BOE compared with the third quarter of 2017.
- Exited the quarter with $130.2 million of cash and cash equivalents.
- In addition, subsequent to September 30, 2018, our Common Stock was admitted to list on the London Stock Exchange.
- Subsequent to the quarter there was an act of sabotage to one of our flow lines close to the Costayaco operations, Villagarzon, Putumayo. No one from Gran Tierra Energy or the local communities were injured however; three members of the Civil Defense authorities did sustain minor injuries. The damage to the flow line was repaired and

back in operation within 24-hours. The appropriate authorities are investigating those responsible and the company is cooperating fully with the authorities in their investigation.

[1] Funds flow from operations and operating netback are non-GAAP measures which do not have any standardized meaning prescribed under GAAP. Refer to the non-GAAP measures disclosure below for a definition and reconciliation of these measures.

(Thousands of U.S. Dollars, unless otherwise indicated)	Three Months Ended September 30,			Three Months Ended June 30,	Nine Months Ended September 30,		
	2018	2017	% Change	2018	2018	2017	% Change
Average Daily Volumes (BOEPD)							
Consolidated							
Working Interest Production Before Royalties	36,170	32,570	11	35,400	35,553	31,305	14
Royalties	(7,571)	(5,055)	(50)	(7,202)	(7,222)	(5,052)	(43)
Production NAR	28,599	27,515	4	28,198	28,331	26,253	8
Decrease (Increase) in Inventory	60	(68)	188	(296)	(403)	(64)	(530)
Sales[1]	28,659	27,447	4	27,902	27,928	26,189	7
Colombia							
Working Interest Production Before Royalties	36,170	32,570	11	35,400	35,553	30,398	17
Royalties	(7,571)	(5,055)	(50)	(7,202)	(7,222)	(4,914)	(47)
Production NAR	28,599	27,515	4	28,198	28,331	25,484	11
Decrease (Increase) in Inventory	60	(68)	188	(296)	(403)	(70)	(476)
Sales[1]	28,659	27,447	4	27,902	27,928	25,414	10
Net Income	$75,295	$3,130	—	$20,300	$113,456	$9,094	—
Operating Netback							
Oil and Natural Gas Sales	$175,118	$103,768	69	$163,446	$476,792	$294,555	62
Operating Expenses	(29,511)	(21,931)	35	(26,732)	(78,019)	(60,547)	29
Workover Expenses	(13,106)	(5,390)	143	(8,327)	(25,922)	(17,919)	45
Transportation Expenses	(7,505)	(6,038)	24	(6,522)	(21,024)	(19,472)	8
Operating Netback[2]	$124,996	$70,409	78	$121,865	$351,827	$196,617	79
G&A Expenses Before Stock-Based Compensation	$3,679	$6,965	(47)	$5,593	$17,254	$22,138	(22)
G&A Stock-Based Compensation	10,132	1,686	501	6,609	19,919	4,738	320
G&A Expenses, Including Stock-Based Compensation	$13,811	$8,651	60	$12,202	$37,173	$26,876	38
EBITDA[2]	$116,668	$60,491	93	$102,278	$307,534	$163,663	88
Funds Flow From Operations[2]	$85,015	$55,128	54	$94,549	$254,312	$151,074	68
Capital Expenditures	$101,463	$71,694	42	$84,394	$258,551	$175,719	47

(Thousands of U.S. Dollars)	As at September 30, 2018	December 31, 2017	% Change
Cash and Cash Equivalents	$130,158	$ 12,326	956
Revolving Credit Facility	$—	$ 148,000	(100)
Senior Notes	$300,000	$ —	—
Convertible Notes	$115,000	$ 115,000	—

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

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

EBITDA, as presented, is defined as net income adjusted for depletion, depreciation and accretion ("DD&A") expenses, interest expense and income tax (recovery) expense. Management uses this supplemental measure to analyze performance and income generated by our principal business activities prior to the consideration of how non-cash items affect that income, and believes that this financial measure is useful supplemental information for investors to analyze our performance and our financial results. A reconciliation from net income to EBITDA is as follows:

	Three Months Ended September 30,		Three Months Ended June 30,	Nine Months Ended September 30,	
(Thousands of U.S. Dollars)	2018	2017	2018	2018	2017
Net income	$75,295	$3,130	$20,300	$113,456	$9,094
Adjustments to reconcile net income to EBITDA					
DD&A expenses	51,630	35,279	46,607	137,698	93,968
Interest expense	7,404	3,989	7,375	20,274	10,415
Income tax (recovery) expense	(17,661)	18,093	27,996	36,106	50,186
EBITDA (non-GAAP)	116,668	60,491	102,278	307,534	163,663

Funds flow from operations, as presented, is defined as net income adjusted for DD&A expenses, deferred tax (recovery) expense, stock-based compensation expense, amortization of debt issuance costs, cash settlement of RSUs, unrealized 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 analyze performance and income generated by our principal business activities prior to the consideration of how non-cash items affect that income or loss, and believes that this financial measure is also useful supplemental information for investors to analyze performance and our financial results. A reconciliation from net income to funds flow from operations is as follows:

	Three Months Ended September 30,		Three Months Ended June 30,	Nine Months Ended September 30,	
(Thousands of U.S. Dollars)	2018	2017	2018	2018	2017
Net income	$75,295	$3,130	$20,300	113,456	$9,094
Adjustments to reconcile net income to funds flow from operations					
DD&A expenses	51,630	35,279	46,607	137,698	93,968
Deferred tax (recovery) expense	(36,769)	13,760	23,169	(118)	36,664
Stock-based compensation expense	10,275	1,752	6,893	20,477	4,935
Amortization of debt issuance costs	816	643	843	2,329	1,868
Cash settlement of RSUs	—	(33)	(240)	(360)	(534)
Unrealized foreign exchange (gain) loss	(672)	(1,380)	1,583	(133)	(304)
Financial instruments (gain) loss	(4,874)	1,675	4,768	6,840	(5,211)
Cash settlement of financial instruments	(10,686)	302	(9,666)	(26,169)	1,518
Loss on sale	—	—	292	292	9,076
Funds flow from operations (non-GAAP)	$85,015	$55,128	$94,549	$254,312	$151,074

Additional Operational Results

	Three Months Ended September 30,			Three Months Ended June 30,	Nine Months Ended September 30,		
	2018	2017	% Change	2018	2018	2017	% Change
(Thousands of U.S. Dollars)							
Oil and natural gas sales	$175,118	$103,768	69	$163,446	$476,792	$294,555	62
Operating expenses	29,511	21,931	35	26,732	78,019	60,547	29
Workover expenses	13,106	5,390	143	8,327	25,922	17,919	45
Transportation expenses	7,505	6,038	24	6,522	21,024	19,472	8
Operating netback(1)	124,996	70,409	78	121,865	351,827	196,617	79
DD&A expenses	51,630	35,279	46	46,607	137,698	93,968	47
G&A expenses before stock-based compensation	3,679	6,965	(47)	5,593	17,254	22,138	(22)
G&A stock-based compensation expense	10,132	1,686	501	6,609	19,919	4,738	320
Severance expenses	1,004	1,164	(14)	1,011	2,015	1,164	73
Equity tax	—	—	—	—	—	1,224	(100)
Foreign exchange (gain) loss	(888)	(1,271)	30	1,924	94	779	(88)
Financial instruments (gain) loss	(4,874)	1,675	(391)	4,768	6,840	(5,211)	231
Interest expense	7,404	3,989	86	7,375	20,274	10,415	95
	68,087	49,487	38	73,887	204,094	129,215	58
Loss on sale	—	—	—	(292)	(292)	(9,076)	(97)
Interest income	725	301	141	610	2,121	954	122
Income before income taxes	57,634	21,223	172	48,296	149,562	59,280	152

Current income tax expense	19,108	4,333	341	4,827	36,224	13,522	168

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Deferred income tax (recovery) expense	(36,769)	13,760	(367)	23,169	(118)	36,664	(100)
	(17,661)	18,093	(198)	27,996	36,106	50,186	(28)
Net income	$75,295	$3,130	—	$20,300	$113,456	$9,094	—
Sales Volumes (NAR)							
Total sales volumes, BOEPD	28,659	27,447	4	27,902	27,928	26,189	7
Brent Price per bbl	$75.97	$52.18	46	$74.90	$72.68	$52.59	38
Consolidated Results of Operations per BOE Sales Volumes NAR							
Oil and natural gas sales	$66.42	$41.09	62	$64.37	$62.54	$41.20	52
Operating expenses	11.19	8.69	29	10.53	10.23	8.46	21
Workover expenses	4.97	2.13	133	3.28	3.40	2.51	35
Transportation expenses	2.85	2.39	19	2.57	2.76	2.72	1
Operating netback[1]	47.41	27.88	70	47.99	46.15	27.51	68
DD&A expenses	19.58	13.97	40	18.36	18.06	13.14	37
G&A expenses before stock-based compensation	1.40	2.76	(49)	2.20	2.26	3.10	(27)
G&A stock-based compensation expense	3.84	0.67	473	2.60	2.61	0.66	295
Severance expenses	0.38	0.46	(17)	0.40	0.26	0.16	63
Equity tax	—	—	—	—	—	0.17	(100)
Foreign exchange (gain) loss	(0.34)	(0.50)	32	0.76	0.01	0.11	(91)
Financial instruments (gain) loss	(1.85)	0.66	(380)	1.88	0.90	(0.73)	223
Interest expense	2.81	1.58	78	2.90	2.66	1.46	82
	25.82	19.60	32	29.10	26.76	18.07	48
Loss on sale	—	—	—	(0.12)	(0.04)	(1.27)	(97)
Interest income	0.27	0.12	125	0.24	0.28	0.13	115
Income before income taxes	21.86	8.40	160	19.01	19.63	8.30	137
Current income tax expense	7.25	1.72	322	1.90	4.75	1.89	151
Deferred income tax (recovery) expense	(13.95)	5.45	(356)	9.12	(0.02)	5.13	(100)
	(6.70)	7.17	(193)	11.02	4.73	7.02	(33)
Net income	$28.56	$1.23	—	$7.99	$14.90	$1.28	—

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

Oil and Gas Production and Sales Volumes, BOEPD

Average Daily Volumes (BOEPD)	Three Months Ended September 30, 2018 Colombia	Three Months Ended September 30, 2017 Colombia
Working Interest Production Before Royalties	36,170	32,570
Royalties	(7,571)	(5,055)
Production NAR	28,599	27,515
Decrease (Increase) in Inventory	60	(68)
Sales	28,659	27,447
Royalties, % of Working Interest Production Before Royalties	21 %	16 %

	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017		
Average Daily Volumes (BOEPD)	Total	Colombia	Brazil	Total
Working Interest Production Before Royalties	35,553	30,398	907	31,305
Royalties	(7,222)	(4,914)	(138)	(5,052)
Production NAR	28,331	25,484	769	26,253
(Increase) Decrease in Inventory	(403)	(70)	6	(64)
Sales	27,928	25,414	775	26,189
Royalties, % of Working Interest Production Before Royalties	20 %	16 %	15 %	16 %

Colombian oil and gas production NAR for the three and nine months ended September 30, 2018 increased by 4% and 11%, respectively, compared with the corresponding periods 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 18,885 bopd before royalties (14,890 bopd NAR) during the three months ended September 30, 2018 compared with 10,743 bopd in the corresponding period of 2017, a 76% increase. Acordionero Field production increased 1,175 bopd before royalties from the three months ended June 30, 2018.

Royalties as a percentage of production for the three and nine months ended September 30, 2018 increased compared with the corresponding periods 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 High Price Royalties.

Operating Netbacks

	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017
(Thousands of U.S. Dollars)	Colombia	Colombia
Oil and Natural Gas Sales	$ 175,118	$ 103,768
Transportation Expenses	(7,505)	(6,038)
	167,613	97,730
Operating Expenses	(29,511)	(21,931)
Workover Expenses	(13,106)	(5,390)
Operating Netback(1)	$ 124,996	$ 70,409
U.S. Dollars Per BOE Sales Volumes NAR		
Brent	$ 75.97	$ 52.18
Quality and Transportation Discounts	(9.55)	(11.09)
Average Realized Price	66.42	41.09
Transportation Expenses	(2.85)	(2.39)
Average Realized Price Net of Transportation Expenses	63.57	38.70
Operating Expenses	(11.19)	(8.69)
Workover Expenses	(4.97)	(2.13)
Operating Netback(1)	$ 47.41	$ 27.88

	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017		
(Thousands of U.S. Dollars)	Total	Colombia	Brazil	Total
Oil and Natural Gas Sales	$ 476,792	$ 286,137	$ 8,418	$ 294,555
Transportation Expenses	(21,024)	(19,122)	(350)	(19,472)
	455,768	267,015	8,068	275,083
Operating Expenses	(78,019)	(58,754)	(1,793)	(60,547)
Workover Expenses	$ (25,922)	$ (17,915)	$ (4)	(17,919)
Operating Netback(1)	$ 351,827	$ 190,346	$ 6,271	$ 196,617
U.S. Dollars Per BOE Sales Volumes NAR				
Brent	$ 72.68	$ 52.59	$ 52.59	$ 52.59
Quality and Transportation Discounts	(10.14)	(11.35)	(12.83)	(11.39)
Average Realized Price	62.54	41.24	39.76	41.20
Transportation Expenses	(2.76)	(2.76)	(1.65)	(2.72)
Average Realized Price Net of Transportation Expenses	59.78	38.48	38.11	38.48
Operating Expenses	(10.23)	(8.47)	(8.47)	(8.46)
Workover Expenses	(3.40)	(2.58)	(0.02)	(2.51)
Operating Netback(1)	$ 46.15	$ 27.43	$ 29.62	$ 27.51

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

measure.

Oil and gas sales for the three and nine months ended September 30, 2018 increased by 69% to $175.1 million and 62% to $476.8 million, respectively, compared with the corresponding periods of 2017. Compared with the prior quarter, oil and gas sales increased by 7%. The increases were due to increased sales volumes and realized oil prices. The following table shows the effect of changes in realized prices and sales volumes on our oil and gas sales for the three and nine months ended September 30, 2018 compared with the prior quarter and the corresponding periods in 2017:

	Third Quarter 2018 Compared with Second Quarter 2018	Third Quarter 2018 Compared with Third Quarter 2017	Nine Months Ended, September 30, 2018 Compared with Nine Months Ended September 30, 2017
Oil and natural gas sales for the comparative period	$ 163,446	$ 103,768	$ 294,555
Realized sales price increase effect	5,397	66,770	162,696
Sales volume increase effect	6,275	4,580	19,541
Oil and natural gas sales for the period ended September 30, 2018	$ 175,118	$ 175,118	$ 476,792

Average realized prices for the three and nine months ended September 30, 2018 increased by 62% and 52%, respectively, compared with the corresponding periods of 2017. Compared with the prior quarter, average realized prices increased by 3%. The increases were commensurate with increases in benchmark oil prices and lower quality and transportation discounts. Average Brent oil prices for the three and nine months ended September 30, 2018 increased by 46% and 38%, respectively, compared with the corresponding periods of 2017 and increased by 1% compared with the prior quarter.

We have options to sell our oil through multiple pipelines and trucking routes. Each transportation route has varying effects on realized sales prices and transportation expenses. We focus on maximizing operating netback. The following table shows the percentage of oil volumes we sold in Colombia using each transportation method for the three and nine months ended September 30, 2018 and 2017 and the prior quarter:

	Three Months Ended September 30,		Three Months Ended June 30,	Nine Months Ended September 30,	
	2018	2017	2018	2018	2017
Volume transported through pipeline	9 %	10 %	9 %	9 %	18 %
Volume sold at wellhead	37 %	57 %	41 %	39 %	54 %
Volume transported via truck	54 %	33 %	50 %	52 %	28 %
	100 %	100 %	100 %	100 %	100 %

Volumes transported through pipeline or via truck receive higher realized prices, but incur higher transportation expenses. Volumes sold at the wellhead have the opposite effect of lower realized prices, offset by lower transportation expenses.

Colombian transportation expenses for the three and nine months ended September 30, 2018 increased by 24% to $7.5 million and by 10% to $21.0 million, compared with the corresponding periods of 2017. On a per BOE basis, Colombian transportation expenses increased by 19% to $2.85, and were comparable at $2.76, respectively compared with the corresponding periods of 2017. The increase in Colombian transportation expenses per BOE in the three months ended September 30, 2018 was due to renegotiation of certain sales contracts, which had higher transportation costs compared to contracts used in 2017.

For the three months ended September 30, 2018, Colombian transportation expenses increased 15% compared with $6.5 million in the prior quarter. On a per BOE basis, transportation expenses increased by 11% to $2.85 from $2.57 in the prior quarter. The increase was primarily due to the use of alternative transportation routes, which had higher costs per BOE.

Higher transportation expenses were more than offset by lower quality and transportation discounts. The following table shows the variance in our average realized prices net of transportation expenses in Colombia for the three and nine months ended September 30, 2018 compared with the prior quarter and the corresponding periods in 2017:

U.S. Dollars Per BOE Sales Volumes NAR	Third Quarter 2018 Compared with Second Quarter 2018	Third Quarter 2018 Compared with Third Quarter 2017	Nine Months Ended, September 30, 2018 Compared with Nine Months Ended September 30, 2017
Average realized price net of transportation expenses for the comparative period	$ 61.80	$ 38.70	$ 38.48
Increase in benchmark prices	1.07	$ 23.79	20.09
Decrease in quality and transportation discounts	0.98	1.54	1.21
Increase in transportation expenses	(0.28)	(0.46)	—
Average realized price net of transportation expenses for the period ended September 30, 2018	$ 63.57	$ 63.57	$ 59.78

Colombian operating expenses for the three and nine months ended September 30, 2018 increased by 35% to $29.5 million and by 33% to $78.0 million, respectively, compared with the corresponding periods in 2017. On a per BOE basis, Colombian operating expenses increased by $2.50 and $1.76, respectively, compared to the corresponding periods of 2017, primarily as a result of higher power generation costs in the Acordionero and Costayaco Fields and field operation maintenance activities. Gas-to-power facility is expected to be finalized during the second quarter of 2019, which will enable consistent power generation and reduce power generation costs.

Colombian operating expenses for the three months ended September 30, 2018 increased by 10% compared with the prior quarter. On a per BOE basis, operating expenses increased by 6%, or $0.66, as a result of higher operating activities during the third quarter of 2018 mentioned in the paragraph above.

Colombia workover expenses increased $2.84 and $0.82 to $4.97 and $3.40 per BOE in the three and nine months ended September 30, 2018, respectively, compared to the corresponding periods in 2017 and increased by $1.69 compared to the prior quarter as a result of replacement of 9 electric submersible pumps during the third quarter of 2018

DD&A Expenses

	Three Months Ended September 30, 2018		Three Months Ended September 30, 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	$51,416	$ 19.50	$33,388	$ 13.22
Peru	—	—	1,057	—
Corporate	214	—	834	—
	$51,630	$ 19.58	$35,279	$ 13.97

	Nine Months Ended September 30, 2018		Nine Months Ended September 30, 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	$135,980	$ 17.84	$88,453	$ 12.75
Brazil	—	—	2,263	10.69
Peru	—	—	1,978	—
Corporate	1,718	—	1,274	—
	$137,698	$ 18.06	$93,968	$ 13.14

DD&A expenses for the three and nine months ended September 30, 2018 increased to $51.6 million ($19.58 per BOE) and $137.7 million ($18.06 per BOE), respectively, from $35.3 million ($13.97 per BOE) and $94.0 million ($13.14 per BOE), respectively, in the corresponding periods 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 7% from $18.36 per BOE in the prior quarter primarily due to higher costs in the depletable base.

G&A Expenses

	Three Months Ended September 30,			Three Months Ended June 30,	Nine Months Ended September 30,		
(Thousands of U.S. Dollars)	2018	2017	% Change	2018	2018	2017	% Change
G&A Expenses Before Stock-Based Compensation	$3,679	$6,965	(47)	$5,593	$17,254	$22,138	(22)
G&A Stock-Based Compensation	10,132	1,686	501	6,609	19,919	4,738	320
G&A Expenses, Including Stock-Based Compensation	$13,811	$8,651	60	$12,202	$37,173	$26,876	38
U.S. Dollars Per BOE Sales Volumes NAR							
G&A Expenses Before Stock-Based Compensation	$1.40	$2.76	(49)	$2.20	$2.26	$3.10	(27)
G&A Stock-Based Compensation	3.84	0.67	473	2.60	2.61	0.66	295
G&A Expenses, Including Stock-Based Compensation	$5.24	$3.43	53	$4.80	$4.87	$3.76	30

For the three and nine months ended September 30, 2018, G&A expenses before stock-based compensation decreased by 47% and 22%, respectively, from the corresponding periods of 2017. The decrease was primarily the result of higher overhead recoveries, partially offset by higher G&A expenses commensurate with our growth. On a per BOE basis, G&A expenses before stock-based compensation decreased 49% and 27%, respectively, from the corresponding periods of 2017.

After stock-based compensation, G&A expenses for the three and nine months ended September 30, 2018 increased by 60% (53% per BOE) to $13.8 million and by 38% (30% per BOE) to $37.2 million, respectively, compared with the corresponding periods in 2017, mainly due to higher G&A Stock-Based Compensation resulting from a higher share price at the quarter end, additional equity compensation awards outstanding as a result of approaching vesting date and improvement in key performance metrics due to the strong Company performance during the quarter. G&A expenses for the three months ended September 30, 2018 increased by 13% (9% per BOE) compared with the prior quarter for the same reason.

Severance

For the three and nine months ended September 30, 2018, severance costs decreased 14% to $1.0 million and increased 73% to $2.0 million, respectively, compared with the corresponding periods in 2017 and decreased 1% compared with the prior quarter.

Foreign Exchange Gains and Losses

For the three and nine months ended September 30, 2018, we had a $0.9 million foreign exchange gain and a $0.1 million loss, respectively, compared with a $1.3 million gain and a $0.8 million loss, respectively, in the corresponding periods 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 realized in the near-term.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Change in the U.S. dollar against the Colombian peso	strengthened by 1%	weakened by 3%	no change —%	weakened by 2%

Financial Instrument Gains and Losses

The following table presents the nature of our financial instruments gains and losses for the three and nine months ended September 30, 2018, and 2017:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Thousands of U.S. Dollars)	2018	2017	2018	2017
Commodity price derivative loss (gain)	$929	$2,489	$20,384	$(3,759)
Foreign currency derivatives loss (gain)	525	(814)	(1,499)	(1,452)
Investment gain	(6,328)	—	(12,045)	—
Financial instruments (gain) loss	$(4,874)	$1,675	$6,840	$(5,211)

Income Tax Expense and Recovery

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Thousands of U.S. Dollars)	2018	2017	2018	2017
Income before income tax	$57,634	$21,223	$149,562	$59,280
Current income tax expense	$19,108	$4,333	$36,224	$13,522
Deferred income tax (recovery) expense	(36,769)	13,760	(118)	36,664
Total income tax (recovery) expense	$(17,661)	$18,093	$36,106	$50,186
Effective tax rate			24%	85%

Current income tax expense was higher in the three and nine months ended September 30, 2018 compared with the corresponding periods of 2017 as a result of higher taxable income in Colombia. The deferred income tax recovery for the three and nine months ended September 30, 2018 of $36.8 million and $0.1 million, respectively, was primarily due to the impact of the release of a portion of the valuation allowance in Colombia, partially offset by the excess tax depreciation compared with accounting depreciation in Colombia.

For the nine months ended September 30, 2018, the difference between the effective tax rate of 24% and the 21% U.S. statutory rate was primarily due to an increase to the impact of foreign taxes, which was partially offset by a decrease in the valuation allowance and other permanent differences.

For the nine months ended September 30, 2017, the difference between the effective tax rate of 85% and the 35% U.S. statutory rate was primarily due the impact of foreign taxes and an increase in the valuation allowance, which were partially offset by other permanent differences.

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

(Thousands of U.S. Dollars)	Third Quarter 2018 Compared with Second Quarter 2018	% change	Third Quarter 2018 Compared with Third Quarter 2017	% change	Nine Months Ended, September 30, 2018 Compared with Nine Months Ended September 30, 2017	% change
Net income for the comparative period	$ 20,300		$ 3,130		$ 9,094	
Increase (decrease) due to:						
Prices	5,397		66,770		162,696	
Sales volumes	6,275		4,580		19,541	
Expenses:						
Operating	(2,779)		(7,580)		(17,472)	
Workover	(4,779)		(7,716)		(8,003)	
Transportation	(983)		(1,467)		(1,552)	
Cash G&A and RSU settlements, excluding stock-based compensation expense	2,154		3,319		5,058	
Severance	7		160		(851)	
Interest, net of amortization of debt issuance costs	(56)		(3,242)		(9,398)	
Realized foreign exchange	557		325		856	
Settlement of financial instruments	(1,020)		(10,988)		(27,687)	
Current taxes	(14,281)		(14,775)		(22,702)	
Equity tax	—		—		1,224	
Other	(26)		501		1,528	
Net change in funds flow from operations[1] from comparative period	(9,534)		29,887		103,238	
Expenses:						
Depletion, depreciation and accretion	(5,023)		(16,351)		(43,730)	
Deferred tax	59,938		50,529		36,782	
Amortization of debt issuance costs	27		(173)		(461)	
Stock-based compensation, net of RSU settlement	(3,622)		(8,556)		(15,716)	
Financial instruments gain or loss, net of financial instruments settlements	10,662		17,537		15,636	
Unrealized foreign exchange	2,255		(708)		(171)	
Loss on sale	292		—		8,784	
Net change in net income	54,995		72,165		104,362	
Net income for the current period	$ 75,295	271 %	$ 75,295	—%	$ 113,456	—%

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

2018 Capital Program

Gran Tierra is forecasting a 2018 capital program of $320 million to $330 million, which is expected to be fully funded by cash from operating activities in 2018 of $330 to $340 million (excluding acquisitions). Approximately 70 to 75% of the capital program will be directed to development activities.

Capital expenditures during the three months ended September 30, 2018, were $101.5 million:

(Thousands of U.S. Dollars)	
Colombia:	
Exploration	$8,630
Development:	
Drilling and Completions	57,223
Facilities	32,170
Other	3,430
	101,453
Corporate	10
	$101,463

During the three months ended September 30, 2018, we drilled the following wells in Colombia:

	Number of wells (Gross)	Number of wells (Net)
Development	8	8
Exploration	1	1
Other	1	1
Total Colombia	10	10

We spud eight development wells and one service well, consisting of seven wells in the Midas Block (Acordionero-25, 26, 27, 28, 29, 30 and 31-i), one in the Chaza Block (Costayaco-36), and one in the La Paloma Block (Juglar-2). Six of these wells were brought on production (Acordionero-25, 26, 27, 28, 29 and Costayaco-36) during the quarter. Additionally, of the wells that were in-progress at June 30, 2018, one development well (Costayaco-35-i) was brought on production, and the exploration well (Siriri-1) was plugged and abandoned.

We also drilled the Chilanguita exploration well in the Alea 1848-A Block, which is currently awaiting a completion rig to test several potential pay zones.

We also continued facilities work at the Acordionero Field on the Midas Block and the Moqueta and Costayaco Fields on the Chaza Block.

During the three months ended September 30, 2018, we acquired WI of the VMM-2 block in the Middle Magdalena Valley Basin for cash consideration of $17.0 million. Subsequent to September 30, 2018, we acquired the remaining 45% WI in the PUT-1 Block in the Putumayo Basin for cash consideration of $28.1 million.

Liquidity and Capital Resources

(Thousands of U.S. Dollars)	As at September 30, 2018	% Change	December 31, 2017
Cash and Cash Equivalents	$130,158	956	$ 12,326
Current Restricted Cash and Cash Equivalents	$1,228	(90)	$ 11,787
Revolving Credit Facility	$—	(100)	$ 148,000
Senior Notes	$300,000	—	$ —

Convertible Notes	$115,000	—	$ 115,000

We believe that our capital resources, including cash on hand, cash generated from operations and available capacity on our credit facility, will provide us with sufficient liquidity to meet our strategic objectives and planned capital program for 2018, given current oil price trends and production levels. In accordance with our investment policy, available cash balances are held in our primary cash management banks or may be invested in U.S. or Canadian government-backed federal, provincial or state securities or other money market instruments with high credit ratings and short-term liquidity. We believe that our current financial position provides us the flexibility to respond to both internal growth opportunities and those available through acquisitions.

At September 30, 2018, we had a revolving credit facility with a syndicate of lenders with a borrowing base of $300 million and we 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 September 30, 2018, we 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 April 1 and October 1 of each year. The Convertible Notes will mature on April 1, 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 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.

Under the terms of our credit facility and Senior Notes, we are required to maintain compliance with certain financial and operating covenants which include: limitations on our ratio of debt to net income plus interest, taxes, depreciation, depletion, amortization, 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 September 30, 2018, we were in compliance with all financial and operating covenants in these agreements. Under the terms of the credit facility and Senior Notes, we are also limited in our ability to make distributions to our shareholders.

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

At September 30, 2018, 96% of our cash and cash equivalents were held by subsidiaries and partnerships outside of Canada and the United States.

In Colombia, we participate in a special exchange regime, and we receive revenue in U.S. dollars offshore. We may also pay invoices denominated in U.S. dollars for our Colombian business from these U.S. dollars received offshore.

Derivative Positions

At September 30, 2018, we 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: October 1, to December 31, 2018	5,000	ICE Brent	$ 55.90	n/a
Participating Swaps: October 1, to December 31, 2018	5,000	ICE Brent	$ 52.50	$ 56.11

At September 30, 2018, current liabilities on our balance sheet included $17.7 million in relation to the above outstanding commodity price derivative positions. We do not have any outstanding commodity price derivative positions relating to 2019.

At September 30, 2018, we 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: October 1, 2018 to December 31, 2018	43,500	14,636	COP	3,000	3,107

[1] At September 30, 2018 foreign exchange rate.

At September 30, 2018, current assets on our balance sheet included $0.1 million in relation to the above outstanding foreign currency derivative positions.

Cash Flows

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

	Nine Months Ended September 30,	
	2018	2017
Sources of cash and cash equivalents:		
Net income	$113,456	$9,094
Adjustments to reconcile net income to EBITDA[(1)] and funds flow from operations[(1)]		
DD&A expenses	137,698	93,968
Interest expense	20,274	10,415
Income tax expense	36,106	50,186
EBITDA	307,534	163,663
Current income tax expense	(36,224)	(13,522)
Stock-based compensation expense	20,477	4,935
Contractual interest and other financing expenses	(17,945)	(8,547)
Cash settlement of RSUs	(360)	(534)
Unrealized foreign exchange loss	(133)	(304)
Financial instruments loss (gain)	6,840	(5,211)
Cash settlement of financial instruments	(26,169)	1,518
Loss on sale	292	9,076
Funds flow from operations	254,312	151,074
Proceeds from bank debt, net of issuance costs	4,988	115,264
Proceeds from issuance of Senior Notes, net of issuance costs	288,087	—
Proceeds from issuance of shares	1,408	—
Changes in non-cash investing working capital	32,638	16,047
Deposit received for sale of Brazil business unit	—	34,481
	581,433	316,866
Uses of cash and cash equivalents:		
Additions to property, plant and equipment	(258,551)	(175,719)
Additions to property, plant and equipment - property acquisitions	(20,100)	(30,410)
Repayment of bank debt	(153,000)	(85,000)
Repurchase of shares of Common Stock	(1,314)	(10,000)
Net changes in assets and liabilities from operating activities	(40,652)	(28,105)
Settlement of asset retirement obligations	(456)	(462)
Foreign exchange loss on cash, cash equivalents and restricted cash and cash equivalents	(402)	(1,060)
	(474,475)	(330,756)
Net increase (decrease) in cash and cash equivalents and restricted cash and cash equivalents	$106,958	$(13,890)

(1) EBITDA and funds flow from operations are a non-GAAP measures which do not have any standardized meaning prescribed under GAAP. Refer to “Financial and Operational Highlights - non-GAAP measures” for a definition and reconciliation of this measure.

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

Off-Balance Sheet Arrangements

As at September 30, 2018, we had no off-balance sheet arrangements.

Contractual Obligations

During February 2018, we issued $300 million aggregate principal amount of the Senior Notes. Refer to Note 5 in the Notes to the Condensed Consolidated Financial Statements (Unaudited) in Part I, Item 1 of this Form 10-Q, incorporated herein by reference, for further information. During the nine months ended September 30, 2018, we fully repaid the balance of $153 million outstanding under our revolving credit facility, which remained undrawn at September 30, 2018.

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

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are disclosed in Item 7 of our 2017 Annual Report on Form 10-K, filed with the SEC on February 27, 2018, and have not changed materially since the filing of that document, other than as follows:

Revenue Recognition

We adopted ASC 606 Revenue from Contracts with Customers with a date of initial application of January 1, 2018 in accordance with the modified retrospective approach. Except for providing enhanced disclosures on our revenue transactions, the application of ASC 606 did not have an impact on our consolidated financial position, results of operations or cash flows.

We evaluate our arrangements with third parties and partners to determine if we act as a principal or an agent. In making this evaluation, management considers if we obtain control of the product delivered, which is indicated by us having the primary responsibility for the delivery of the product, having ability to establish prices or having inventory risk. If we act in the capacity of an agent rather than as a principal in transaction, then the revenue is recognized on a net-basis, only reflecting the fee realized by us from the transaction. When determining if we acted as a principal or as an agent in transactions, we determine if we obtain control of the product. As part of this assessment, management considered detailed criteria for revenue recognition set out in ASC 606.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity price risk

Our principal market risk relates to oil prices. Oil prices are volatile and unpredictable and influenced by concerns over world supply and demand imbalance and many other market factors outside of our control. Most of our revenues are from oil sales at prices which reflect the blended prices received upon shipment by the purchaser at defined sales points or are defined by contract relative to ICE Brent and adjusted for quality each month.

We have entered into commodity price derivative contracts to manage the variability in cash flows associated with the forecasted sale of our oil production, reduce commodity price risk and provide a base level of cash flow in order to assure we can execute at least a portion of our capital spending.

Foreign currency risk

Foreign currency risk is a factor for our company but is ameliorated to a certain degree by the nature of expenditures and revenues in the countries where we operate. Our reporting currency is U.S. dollars and 100% of our revenues are related to the U.S. dollar price of Brent or WTI oil. We receive 100% of our revenues in U.S. dollars and the majority of our capital expenditures is in U.S. dollars or are based on U.S. dollar prices. The majority of income and value added taxes and G&A expenses in Colombia are in local currency. Certain G&A expenses incurred at our head office in Canada are denominated in Canadian dollars. While we operate in South America exclusively, the majority of our acquisition expenditures have been valued and paid in U.S. dollars.

We have entered into foreign currency derivative contracts to manage the variability in cash flows associated with our forecasted Colombian peso denominated costs.

Additionally, foreign exchange gains and losses result primarily from the fluctuation of the U.S. dollar to the Colombian peso due to our current and deferred tax liabilities, which are monetary liabilities, denominated in the local currency of the Colombian foreign operations. As a result, a foreign exchange gain or loss must be calculated on conversion to the U.S. dollar functional currency.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. We are exposed to interest rate fluctuations on our revolving credit facility, which bears floating rates of interest. At September 30, 2018, our outstanding revolving credit facility was nil (December 31, 2017 - $148.0 million).

Further Information

See Note 10 in the Notes to the Condensed Consolidated Financial Statements (Unaudited) in Part I, Item 1 of this Quarterly Report on Form 10-Q, which is incorporated herein by reference, for further information regarding our derivative contracts, including the notional amounts and call and put prices by expected (contractual) maturity dates. Expected cash flows from the derivatives equaled the fair value of the contract. The information is presented in U.S. dollars because that is our reporting currency. We do not hold any of these derivative contracts for trading purposes.

Item 4. Controls and Procedures

Disclosure Controls and Procedures

We have established disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, or Exchange Act). Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by Gran Tierra in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report, as required by Rule l3a-15(b) of the Exchange Act. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that Gran Tierra's disclosure controls and procedures were effective as of September 30, 2018.

Changes in Internal Control over Financial Reporting

During the quarter ended September 30, 2018, we implemented a new company-wide Enterprise Resource Planning ("ERP") system, which handles the business and financial processes of our operations and our corporate function. We have modified our existing internal controls related to the ERP system implementation. Other than a new ERP system implementation, there were no other changes in our internal control over financial reporting during the quarter ended September 30, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - Other Information

Item 1. Legal Proceedings

See Note 9 in the Notes to the Condensed Consolidated Financial Statements (Unaudited) in Part I, Item 1 of this Quarterly Report on Form 10-Q, which is incorporated herein by reference, for any material developments with respect to matters previously reported in our Annual Report on Form 10-K for the year ended December 31, 2017, and any material matters that have arisen since the filing of such report.

Item 1A. Risk Factors

See Part I, Item 1A Risk Factors of our 2017 Annual Report on Form 10-K. Other than the risk factor set forth below, the risks facing our company have not changed materially from those set forth in Part I, Item 1A Risk Factors of our 2017 Annual Report on Form 10-K.

Shares of our Common Stock are 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.

Shares of our Common Stock are listed on the NYSE American, the TSX and 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 our transfer agent or registrar. This could result in time delays and additional cost for shareholders of the Common Stock.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuer Purchases of Equity Securities

	(a) Total Number of Shares Purchased[1]	(b) Average Price Paid per Share [2]	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares that May Yet be Purchased Under the Plans or Programs [3]
July 1-31, 2018	—	—	—	18,800,320
August 1-31, 2018	35,200	3.00	35,200	18,765,120
September 1- 30, 2018	—	—	—	18,765,120
	35,200	3.00	35,200	18,765,120

[1] Based on settlement date.

[2] Exclusive of commissions paid to the broker to repurchase the Common Stock.

[3] On March 7, 2018, we announced that we intended to implement a share repurchase program (the "2018 Program") through the facilities of the TSX and eligible alternative trading platforms in Canada. We received regulatory approval from the TSX to commence the 2018 Program on March 12, 2018. We are able to purchase at prevailing market prices up to 19,269,732 shares of Common Stock, representing approximately 5% of our issued and outstanding shares of Common Stock as of March 8, 2018.

Shares purchased pursuant to the 2018 Program to date have been canceled. The 2018 Program will expire on March 11, 2019, or earlier if the 5.00% share maximum is reached. The 2018 Program could be terminated by us 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.

Item 6. Exhibits

Exhibit No.	Description	Reference
2.1	Plan of Conversion, dated October 31, 2016.	Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K, filed with the SEC on November 4, 2016 (SEC File No. 001-34018).
3.1	Certificate of Incorporation.	Incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K, filed with the SEC on November 4, 2016 (SEC File No. 001-34018).
3.2	Bylaws of Gran Tierra Energy Inc.	Incorporated by reference to Exhibit 3.4 to the Current Report on Form 8-K, filed with the SEC on November 4, 2016 (SEC File No. 001-34018).
3.3	Certificate of Retirement dated July 9, 2018	Incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed with the SEC on July 9, 2018 (SEC File No. 001-34018).
4.1	Indenture related to the 5.00% Convertible Senior Notes due 2021, dated as of April 6, 2016, between Gran Tierra Energy Inc. and U.S. Bank National Association	Incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed with the SEC on April 6, 2016 (SEC File No. 001-34018).
4.2	Form of 5.00% Convertible Senior Notes due 2021	Incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed with the SEC on April 6, 2016 (SEC File No. 001-34018).
4.3	Subscription Receipt Agreement, dated July 8, 2016, by and between Gran Tierra Energy Inc. and Computershare Trust Company of Canada.	Incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed with the SEC on July 14, 2016 (SEC File No. 001-34018).
4.4	Form of Registration Rights Agreement.	Incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K, filed with the SEC on July 14, 2016 (SEC File No. 001-34018).
4.5	Purchase Agreement, dated February 8, 2018, by and among Gran Tierra Energy International Holdings Ltd., Gran Tierra Energy Inc. and	Incorporated by reference to Exhibit 10.1 to the Current Report on Form

	the subsidiary guarantors named therein, and Credit Suisse Securities (USA) LLC and RBC Capital Markets, LLC, as Representatives of the several initial purchasers.	8-K filed with the SEC on February 9, 2018 (SEC File No. 001-34018).
4.6	Indenture related to the 6.25% Senior Notes due 2025, dated as of February 15, 2018, between Gran Tierra Energy International Holdings Ltd., the Guarantors named therein and U.S. Bank National Association	Incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed with the SEC on February 16, 2018 (SEC File No. 001-34018).
4.7	Form of 6.25% Senior Notes due 2025	Incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed with the SEC on February 16, 2018 (SEC File No. 001-34018).
10.1	Transaction Agreement, dated July 18, 2018, between Adrian Coral Pantoja and James Evans, as legal representative of Gran Tierra Energy Colombia Ltd.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the SEC on July 23, 2018 (SEC File No. 001-34018).
31.1	Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith.
31.2	Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith.
32.1	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Furnished herewith.

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

+ Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. Gran Tierra undertakes to furnish supplemental copies of any of the omitted schedules upon request by the SEC.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

GRAN TIERRA ENERGY INC.

Date: November 1, 2018	/s/ Gary S. Guidry By: Gary S. Guidry President and Chief Executive Officer (Principal Executive Officer)
Date: November 1, 2018	/s/ Ryan Ellson By: Ryan Ellson Chief Financial Officer (Principal Financial and Accounting Officer)