2020

Q3 Report

TSX BTE | NYSE BTE

BAYTEX ANNOUNCES THIRD QUARTER 2020 FINANCIAL AND OPERATING RESULTS AND BOARD APPOINTMENT

CALGARY, ALBERTA (November 2, 2020) - Baytex Energy Corp. ("Baytex")(TSX: BTE, NYSE: BTE.BC) reports its operating and financial results for the three and nine months ended September 30, 2020 (all amounts are in Canadian dollars unless otherwise noted).

"We have made tremendous progress to re-set our business in the face of extremely volatile crude oil markets. Our third quarter results demonstrate the success of our actions as we generated free cash flow of $60 million and increased financial liquidity to $344 million. I am also especially pleased with our response to the Covid pandemic with intensified efforts to improve all aspects of our cost structure and capital efficiencies, while protecting the health and safety of our personnel," commented Ed LaFehr, President and Chief Executive Officer.

Q3 2020 Highlights

- Generated production of 77,814 boe/d (82% oil and NGL) in Q3/2020 and 82,907 boe/d (82% oil and NGL) for the first nine months of 2020.
- Delivered adjusted funds flow of $79 million ($0.14 per basic share) in Q3/2020 and $229 million ($0.41 per basic share) for the first nine months of 2020.
- Generated free cash flow of $60 million ($0.11 per basic share) in Q3/2020 and $16 million ($0.03 per basic share) for the first nine months of 2020.
- Realized an operating netback of $17.05/boe in Q3/2020, up from $5.96/boe in Q2/2020.
- Reduced net debt by $89 million during the third quarter through a combination of free cash flow and the Canadian dollar strengthening relative to the U.S. dollar.
- Maintained undrawn credit capacity of $426 million and liquidity, net of working capital, of $344 million.

2020 Outlook and Revised Guidance

We have responded aggressively to the downturn brought on by Covid-19 as we minimize capital spending, identify cost savings and maintain our liquidity.

We expect production to average approximately 80,000 boe/d, which represents the mid-point of our guidance range of 78,000 to 82,000 boe/d. Annual capital spending is forecast to be $260 to $290 million, an approximate 50% reduction from our original plan of $500 to $575 million.

We are also reducing our full-year 2020 operating expense guidance by 7% (at the mid-point) to $11.20 to $11.40/boe. We remain intensely focused on driving further efficiencies to capture and sustain cost reductions identified during this downturn, while protecting the health and safety of our personnel.

After two quarters of little to no capital spending in Canada, we have resumed drilling activity during the fourth quarter. We have mobilized two drilling rigs to execute a 30-well drilling program in the Viking and completed two Duvernay wells drilled earlier this year. In addition, with the increase in natural gas prices, we have identified opportunities in west-central Alberta at Pembina O'Chiese to drill natural gas wells with strong economics and capital efficiencies and have two wells planned for this winter.

The following table summarizes our updated 2020 guidance. We are in the process of setting our 2021 capital budget, the details of which are expected to be released in December following approval by our Board of Directors.

	2020 Guidance (1)	**2020 Revised Guidance**
Exploration and development expenditures	$260 - $290 million	no change
Production (boe/d)	78,000 - 82,000	~ 80,000
Expenses:		
Royalty rate	~ 18.5%	~ 18%
Operating	$11.75 - $12.50/boe	$11.20 - $11.40/boe
Transportation	$0.95 - $1.05/boe	no change
General and administrative	$38 million ($1.30/boe)	no change
Interest	$112 million ($3.84/boe)	$108 million ($3.70/boe)
Leasing expenditures	$7 million	$6 million
Asset retirement obligations	$10 million	$8 million

Note:

(1) As announced on June 25, 2020

During the third quarter we began to benefit from our actions to reduce capital, capture cost savings and maintain liquidity. We generated free cash flow of $60 million during the quarter and $16 million through the first nine months of this year and also increased our financial liquidity to $344 million.

The following table summarizes the important measures we have undertaken to position us for success as markets recover.

Action	**2020 Highlights**
Negotiated bank credit facility extension and refinanced long-term notes	• Extended maturity of bank credit facilities to April 2024 • Issued US$500 million principal amount of long-term notes due April 2027 • Redeemed two series of senior unsecured notes – US$400 million due 2021 and $300 million due 2022
Dynamic response to oil price collapse	• Identified cost savings of ~ $100 million, capital budget reduced by ~ 50% • Maintained liquidity of > $300 million • Maintained strong operating efficiency • Active hedge strategy implemented to preserve financial liquidity • Accessed available government assistance
High graded portfolio and economic inventory	• Capital reduction has re-set production base to ~ 75,000 boe/d • Fully funded sustaining capital program at US$40 to US$45/bbl WTI • Improved capital efficiencies and moderated production decline rate
Established Covid-19 task force and flexible working team	• Effective response to Covid-19 with on-going training, communication and work strategies

	Three Months Ended			Nine Months Ended	
	September 30, 2020	June 30, 2020	September 30, 2019	**September 30, 2020**	September 30, 2019
FINANCIAL					
(thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 252,538**	$ 152,689	$ 424,600	**$ 741,841**	$ 1,360,024
Adjusted funds flow [1]	**78,508**	17,887	213,379	**229,330**	670,279
Per share – basic	**0.14**	0.03	0.38	**0.41**	1.20
Per share – diluted	**0.14**	0.03	0.38	**0.41**	1.20
Net income (loss)	**(23,444)**	(138,463)	15,151	**(2,660,124)**	105,313
Per share – basic	**(0.04)**	(0.25)	0.03	**(4.75)**	0.19
Per share – diluted	**(0.04)**	(0.25)	0.03	**(4.75)**	0.19
Capital Expenditures					
Exploration and development expenditures [1]	**$ 15,902**	$ 9,852	$ 139,085	**$ 202,531**	$ 399,174
Acquisitions, net of divestitures	**(98)**	(11)	(30)	**(149)**	1,617
Total oil and natural gas capital expenditures	**$ 15,804**	$ 9,841	$ 139,055	**$ 202,382**	$ 400,791
Net Debt					
Credit facilities [2]	**$ 624,826**	$ 704,135	$ 570,792	**$ 624,826**	$ 570,792
Long-term notes [2]	**1,199,160**	1,225,395	1,359,480	**1,199,160**	1,359,480
Long-term debt	**1,823,986**	1,929,530	1,930,272	**1,823,986**	1,930,272
Working capital deficiency	**82,093**	65,423	41,067	**82,093**	41,067
Net debt [1]	**$ 1,906,079**	$ 1,994,953	$ 1,971,339	**$ 1,906,079**	$ 1,971,339
Shares Outstanding - basic (thousands)					
Weighted average	**561,128**	560,512	557,888	**560,484**	556,651
End of period	**561,163**	560,545	557,972	**561,163**	557,972
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 40.93**	$ 27.85	$ 56.45	**$ 38.32**	$ 57.06
MEH oil (US$/bbl)	**41.63**	26.40	61.07	**39.19**	62.63
MEH oil differential to WTI (US$/bbl)	**0.70**	(1.45)	4.62	**0.87**	5.57
Edmonton par ($/bbl)	**49.83**	29.85	68.41	**43.70**	69.59
Edmonton par differential to WTI (US$/bbl)	**(3.51)**	(6.31)	(4.66)	**(6.04)**	(4.70)
WCS heavy oil ($/bbl)	**42.40**	22.70	58.39	**33.34**	60.24
WCS differential to WTI (US$/bbl)	**(9.09)**	(11.47)	(12.24)	**(13.70)**	(11.74)
Natural gas					
NYMEX (US$/mmbtu)	**$ 1.98**	$ 1.72	$ 2.23	**$ 1.88**	$ 2.67
AECO ($/mcf)	**2.18**	1.91	1.04	**2.08**	1.39
CAD/USD average exchange rate	**1.3316**	1.3860	1.3207	**1.3541**	1.3292

	Three Months Ended			Nine Months Ended	
	September 30, 2020	June 30, 2020	September 30, 2019	**September 30, 2020**	September 30, 2019
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**34,101**	38,951	42,829	**39,570**	43,479
Heavy oil (bbl/d)	**22,138**	11,832	25,712	**20,946**	26,637
NGL (bbl/d)	**7,417**	7,634	9,543	**7,624**	10,745
Total liquids (bbl/d)	**63,656**	58,417	78,084	**68,140**	80,861
Natural gas (mcf/d)	**84,945**	84,546	101,054	**88,602**	103,587
Oil equivalent (boe/d @ 6:1) (3)	**77,814**	72,508	94,927	**82,907**	98,125
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense (4)	**$ 241,865**	$ 147,229	$ 411,650	**$ 704,351**	$ 1,309,396
Royalties	**(40,052)**	(29,156)	(75,017)	**(125,928)**	(242,959)
Operating expense	**(73,447)**	(73,680)	(97,377)	**(251,597)**	(298,143)
Transportation expense	**(6,372)**	(5,031)	(9,903)	**(21,745)**	(35,102)
Operating netback (1)	**$ 121,994**	$ 39,362	$ 229,353	**$ 305,081**	$ 733,192
General and administrative	**(7,741)**	(7,438)	(9,934)	**(24,954)**	(35,576)
Cash financing and interest	**(25,418)**	(27,387)	(26,752)	**(81,340)**	(83,028)
Realized financial derivatives gain (loss)	**(9,743)**	13,624	20,857	**30,731**	52,664
Other (5)	**(584)**	(274)	(145)	**(188)**	3,027
Adjusted funds flow (1)	**$ 78,508**	$ 17,887	$ 213,379	**$ 229,330**	$ 670,279
Netback (per boe)					
Total sales, net of blending and other expense (4)	**$ 33.79**	$ 22.31	$ 47.14	**$ 31.01**	$ 48.88
Royalties	**(5.59)**	(4.42)	(8.59)	**(5.54)**	(9.07)
Operating expense	**(10.26)**	(11.17)	(11.15)	**(11.08)**	(11.13)
Transportation expense	**(0.89)**	(0.76)	(1.13)	**(0.96)**	(1.31)
Operating netback (1)	**$ 17.05**	$ 5.96	$ 26.27	**$ 13.43**	$ 27.37
General and administrative	**(1.08)**	(1.13)	(1.14)	**(1.10)**	(1.33)
Cash financing and interest	**(3.55)**	(4.15)	(3.06)	**(3.58)**	(3.10)
Realized financial derivatives gain (loss)	**(1.36)**	2.06	2.39	**1.35**	1.97
Other (5)	**(0.09)**	(0.03)	(0.03)	**---**	0.11
Adjusted funds flow (1)	**$ 10.97**	$ 2.71	$ 24.43	**$ 10.10**	$ 25.02

Notes:

(1) The terms "adjusted funds flow", "exploration and development expenditures", "net debt" and "operating netback" do not have any standardized meaning as prescribed by Canadian Generally Accepted Accounting Principles ("GAAP") and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. See the advisory on non-GAAP measures at the end of this press release.

(2) Principal amount of instruments. The carrying amount of debt issue costs associated with the credit facilities and long-term notes are excluded on the basis that these amounts have been paid by Baytex and do not represent an additional source of capital or repayment obligations.

(3) Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. The use of boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(4) Realized heavy oil prices are calculated based on sales dollars, net of blending and other expense. We include the cost of blending diluent in our realized heavy oil sales price in order to compare the realized pricing on our produced volumes to the WCS benchmark.

(5) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and share-based compensation. Refer to the Q3/2020 MD&A for further information on these amounts.

Q3/2020 Results

Production during the third quarter averaged 77,814 boe/d (82% oil and NGL), as compared to 72,508 boe/d (81% oil and NGL) in Q2/2020. The higher production reflects the re-start of previously shut-in volumes in Canada, partially offset by lower activity in the Viking and Eagle Ford. Our third quarter production was reduced by approximately 5,000 boe/d due to voluntary shut-ins. Exploration and development spending totaled a modest $16 million during the third quarter.

We delivered adjusted funds flow of $79 million ($0.14 per basic share) in Q3/2020 and generated an operating netback of $17.05/boe ($15.69/boe inclusive of realized financial derivatives loss). The Eagle Ford generated an operating netback of $18.99/boe and our Canadian operations generated an operating netback of $15.90/boe.

We continue to emphasize cost reductions across all facets of our organization. Through the first nine months of 2020 our team has driven operating costs down to $11.08/boe, despite lower production volumes. This compares favorably to our guidance range of $11.75 to $12.50/boe. As a result, we are reducing our full-year 2020 operating expense guidance by 7% (at the mid-point) to $11.20 to $11.40/boe.

Eagle Ford and Viking Light Oil

Production in the Eagle Ford averaged 28,650 boe/d (77% oil and NGL) during Q3/2020, as compared to 34,817 boe/d in Q2/2020. The lower volumes reflect reduced completion activity as we adjusted our development plan in response to volatile commodity prices. We commenced production from six (0.8 net) wells during the third quarter, as compared to 47 (10.7 net) in the first half of 2020. Activity in the Eagle Ford has recently resumed and we have 0.75 net drilling rigs and 0.5 net frac crews running on our lands. We expect to bring approximately 16 net wells on production in the Eagle Ford in 2020.

Production in the Viking averaged 18,774 boe/d (91% oil and NGL) during Q3/2020, as compared to 19,717 boe/d in Q2/2020. We had previously suspended all drilling in the Viking, and as such, there was limited activity during the third quarter. In the first nine months of 2020, we invested $77 million on exploration and development in the Viking and commenced production from 83 (78.5 net) wells. After two quarters of minimal capital spend, we have resumed drilling activity in the Viking with two drillings rigs mobilized to execute a 30-well drilling program during the fourth quarter.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster produced a combined 24,791 boe/d (89% oil and NGL) during the third quarter, as compared to 13,082 boe/d in Q2/2020. The increased production reflects the re-start of previously shut-in production as operating netbacks improved. The quarterly impact of voluntary shut-ins for heavy oil was approximately 5,000 boe/d, down from 17,000 boe/d in Q2/2020. We currently have approximately 2,000 boe/d of heavy oil production shut-in. We had previously suspended all heavy oil drilling, and as such, there was limited activity during the third quarter. In the first nine month of 2020, we invested $41 million on exploration and development and drilled 33 (33.0 net) wells.

Pembina Area Duvernay Light Oil

Production in the Pembina Duvernay averaged 1,474 boe/d (79% oil and NGL) during Q3/2020, as compared to 717 boe/d in Q2/2020. The increased production during the third quarter reflects the re-start of previously shut-in production as operating netbacks improved.

In Q1/2020, we drilled two wells in the core of our Pembina acreage, bringing total wells drilled to nine in this area. These two wells were fracture stimulated in October using a “plug and perf” system with fracture diversion technology. The wells are scheduled to be placed on production in November. The two wells confirm visibility to a $7.0 million well cost in a full development scenario. The success of our drilling program in the Pembina area has significantly de-risked our approximately 38-kilometre long acreage fairway, where we hold 232 sections (100% working interest) of Duvernay land.

Financial Liquidity

Our credit facilities total approximately $1.07 billion and have a maturity date of April 2, 2024. These are not borrowing base facilities and do not require annual or semi-annual reviews. As of September 30, 2020, we had $426 million of undrawn capacity on our credit facilities, resulting in liquidity, net of working capital, of $344 million. In addition, our first long-term note maturity of US$400 million is not until June 2024.

Our net debt, which includes our credit facilities, long-term notes and working capital, totaled $1.9 billion at September 30, 2020, down from $2.0 billion at June 30, 2020. Based on the forward strip, we expect to maintain our financial liquidity and remain onside with our financial covenants.

Financial Covenants

The following table summarizes the financial covenants applicable to the credit facilities and Baytex's compliance therewith as at September 30, 2020.

Covenant Description	Position as at September 30, 2020	Covenant
Senior Secured Debt[1] to Bank EBITDA[2] (Maximum Ratio)	1.1:1.0	3.5:1.0
Interest Coverage[3] (Minimum Ratio)	5.4:1.0	2.0:1.0

Notes:

(1) Senior Secured Debt is defined as the principal amount of the credit facilities and other secured obligations identified in the credit agreement. As at September 30, 2020, the Company's Senior Secured Debt totaled $640.3 million which includes $624.8 million of principal amounts outstanding and $15.5 million of letters of credit.

(2) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expense, income tax, non-recurring losses, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration and evaluation expense, impairment, deferred income tax expense or recovery, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation) and is calculated based on a trailing twelve month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the twelve months ended September 30, 2020 was $566.1 million.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expense, excluding accretion of debt issue costs and asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expense, excluding accretion of debt issue costs and asset retirement obligations, for the twelve months ended September 30, 2020 was $105.2 million.

Risk Management

To manage commodity price movements, we utilize various financial derivative contracts and crude-by-rail to reduce the volatility of our adjusted funds flow. The following table summarizes our crude oil hedges in place.

	Q4/2020	2021
WTI Fixed Hedges		
Volumes (bbl/d)	8,000	---
Fixed Price (US$/bbl)	$42.78	---
WTI 3-Way Option [1]		
Volumes (bbl/d)	24,500	13,500
Baytex Receives [2] [3] [4]	WTI plus US$7.60	US$45
Total Volumes (bbl/d)	32,500	13,500

Notes:

(1) WTI 3-way options consist of a sold put, a bought put and a sold call. Baytex's average sold put, bought put and sold call for Q4/2020 are US$50.44/bbl, US$58.04/bbl and US$63.06/bbl, respectively. Baytex's average sold put, bought put and sold call for 2021 are US$35/bbl, US$45/bbl and US$53.57/bbl, respectively.

(2) For Q4/2020, Baytex receives WTI plus US$7.60/bbl when WTI is at or below US$50.44/bbl; Baytex receives US$58.04/bbl when WTI is between US$50.44/bbl and US$58.04/bbl; Baytex receives WTI when WTI is between US$58.04/bbl and US$63.06/bbl; and Baytex receives US$63.06/bbl when WTI is above US$63.06/bbl.

(3) For 2021, Baytex receives WTI plus US$10/bbl when WTI is at or below US$35/bbl; Baytex receives US$45/bbl when WTI is between US$35/bbl and US$45/bbl; Baytex receives WTI when WTI is between US$45/bbl and US$53.57; and Baytex receives US$53.57/bbl when WTI is above US$53.57/bbl.

(4) Based on the forward strip for the balance of 2020, Baytex will receive WTI plus US$7.60/bbl. Based on the forward strip for 2021, Baytex will receive US$45/bbl.

For Q4/2020, we also have WTI-MSW basis differential swaps for 5,000 bbl/d of our light oil production in Canada at US$6.15/bbl and WCS differential hedges on 6,500 bbl/d at a WTI-WCS differential of US$16.27/bbl.

We also have WTI-MSW differential hedges on approximately 40% of our expected 2021 Canadian light oil production at US$5.17/bbl and WCS differential hedges on approximately 45% of our expected 2021 heavy oil production at a WTI-WCS differential of approximately US$13.50/bbl.

A complete listing of our financial derivative contracts can be found in Note 17 to our Q3/2020 financial statements.

Board Appointment

The Board of Directors is pleased to announce the appointment of Steve Reynish as a director of Baytex.

“We are very pleased that Steve has joined the Baytex board. His strategic perspective and tremendous breadth of experience across technology, ESG, marketing, and corporate development will serve the board and Baytex well in the years ahead,” commented Mark Bly, Chairman of Baytex.

Mr. Reynish is currently the President and Chief Executive Officer of Enlighten Innovations, a private Calgary based clean energy technology organization which he joined in 2020. Immediately prior to Enlighten Mr. Reynish served as an Executive Vice President at Suncor Energy Inc. for eight years in a variety of capacities where he was accountable for the company’s strategy, ESG and corporate development initiatives, new technology development, joint venture and commercial portfolios - all instrumental in positioning Suncor as a top-tier Western Canadian based integrated energy company. Prior to Suncor, Mr. Reynish served as President of Marathon Oil Canada, which he joined through the acquisition of Western Oil Sands where he was Executive Vice President, Operations. Prior to his entry into Canada, he held senior positions within the Anglo American Group, including Vice President of Mining of Anglo Base Metals in Johannesburg and Chief Executive Officer of Bindura Nickel in Zimbabwe. Mr. Reynish holds a Masters degree in Mining Engineering and an MBA, both earned in the UK. He has completed Post Graduate studies at IMD and the Wharton School. He is a member of the board of Energy Safety Canada, the Institute of Corporate Directors (ICD) and National Association of Corporate Directors (NCAD), and a former Member of the Board of Governors of the Oxford Institute of Energy Studies, the Canadian Associated of Petroleum Produces (CAPP) and the Canada Institute.

NYSE Delisting

On March 24, 2020 we received notice from the New York Stock Exchange (“NYSE”) that Baytex was no longer in compliance with one of the NYSE’s continued listing standards because the average closing price of Baytex’s common shares was less than US$1.00 per share over a consecutive 30 trading period. At this time, Baytex has not regained compliance and expects that its common shares will be delisted from the NYSE on December 3, 2020. This will not affect Baytex’s business operations and will not affect the continued listing and trading of Baytex’s common shares on the Toronto Stock Exchange. Currently, over 80% of the daily trading in Baytex common shares occurs in Canada, ensuring investors will retain significant trading liquidity going forward. In addition, Baytex expects to realize significant cost savings over time as a result of the delisting.

DRIP Termination

Baytex is formally terminating its dividend reinvestment plan (“DRIP”). All participants (as defined in the DRIP) effective as of the termination date, will be issued a certificate for any common shares and a cheque for any cash balance remaining in the participants’ account pursuant to the terms of the plan.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three and nine months ended September 30, 2020 and the related Management's Discussion and Analysis of the operating and financial results can be accessed on our website at www.baytexenergy.com and will be available shortly through SEDAR at www.sedar.com and EDGAR at www.sec.gov/edgar.shtml.

Conference Call Tomorrow
9:00 a.m. MST (11:00 a.m. EST)

Baytex will host a conference call tomorrow, November 3, 2020, starting at 9:00am MST (11:00am EST). To participate, please dial toll free in North America 1-800-319-4610 or international 1-416-915-3239. Alternatively, to listen to the conference call online, please enter http://services.choruscall.ca/links/baytexq320201103.html in your web browser.

An archived recording of the conference call will be available shortly after the event by accessing the webcast link above. The conference call will also be archived on the Baytex website at www.baytexenergy.com.

Advisory Regarding Forward-Looking Statements

In the interest of providing Baytex's shareholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements in this press release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "believe", "continue", ""estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this press release speak only as of the date thereof and are expressly qualified by this cautionary statement.

Specifically, this press release contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; our guidance for 2020 exploration and development expenditures, production, royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligations; that we are focused on further efficiencies to capture and sustain cost reductions while protecting the health and safety of our personnel; our drilling plans in Canada; that we plan to release our 2021 capital budget in December of 2020; that we have a production base of ~75,000 boe/d and a fully funded sustaining capital program at US$40 to US$45/bbl WTI; that we expect to bring 16 net wells on production in the Eagle Ford in 2020 and execute a 30 well program in the Viking in Q4/2020; that we have confirmed visibility to a $7.0 million well cost in the Duvernay; that we have de-risked our approximately 38-kilometer acreage fairway in the Pembina Duvernay; that we expect to maintain our financial liquidity and remain onside our financial covenants based on the forward strip; that we use financial derivative contracts and crude-by-rail to reduce adjusted funds flow volatility and the percentage of our expected production in 2021 of Canadian light oil and heavy oil for which we have hedged the differential to WTI; that we expect to be delisted from the NSYE on December 3rd, 2020, that we do not expect the delisting to affect our business operations or the listing and trading of our common shares on the TSX, that the TSX will provide investors significant trading liquidity and that we expect to realize significant cost savings.

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices and price differentials (including the impacts of COVID-19); availability and cost of gathering, processing and pipeline systems; failure to comply with the covenants in our debt agreements; the availability and cost of capital or borrowing; that our credit facilities may not provide sufficient liquidity or may not be renewed; risks associated with a third-party operating our Eagle Ford properties; the cost of developing and operating our assets; depletion of our reserves; risks associated with the exploitation of our properties and our ability to acquire reserves; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; changes in government regulations that affect the oil and gas industry; regulations regarding the disposal of fluids; changes in environmental, health and safety regulations; public perception and its influence on the regulatory regime; restrictions or costs imposed by climate change initiatives; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; risks of counterparty default; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects; risks related to our thermal heavy oil projects; alternatives to and changing demand for petroleum products; risks associated with our use of information technology systems; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control.

These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2019, filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission and in our other public filings

The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

Non-GAAP Financial and Capital Management Measures

In this news release, we refer to certain financial measures (such as adjusted funds flow, exploration and development expenditures, free cash flow, net debt and operating netback) which do not have any standardized meaning prescribed by Canadian GAAP (''non-GAAP measures'') and are considered non-GAAP measures. While adjusted funds flow, exploration and development expenditures, free cash flow, net debt and operating netback are commonly used in the oil and gas industry, our determination of these measures may not be comparable with calculations of similar measures for other issuers.

Adjusted funds flow is not a measurement based on generally accepted accounting principles ("GAAP") in Canada, but is a financial term commonly used in the oil and gas industry. We define adjusted funds flow as cash flow from operating activities adjusted for changes in non-cash operating working capital and asset retirement obligations settled. Our determination of adjusted funds flow may not be comparable to other issuers. We consider adjusted funds flow a key measure that provides a more complete understanding of operating performance and our ability to generate funds for exploration and development expenditures, debt repayment, settlement of our abandonment obligations and potential future dividends.

In addition, we use a ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. Changes in non-cash working capital are eliminated in the determination of adjusted funds flow as the timing of collection, payment and incurrence is variable and by excluding them from the calculation we are able to provide a more meaningful measure of our cash flow on a continuing basis. For a reconciliation of adjusted funds flow to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the three and nine months ended September 30, 2020.

Exploration and development expenditures is not a measurement based on GAAP in Canada. We define exploration and development expenditures as additions to exploration and evaluation assets combined with additions to oil and gas properties. Our definition of exploration and development expenditures may not be comparable to other issuers. We use exploration and development expenditures to measure and evaluate the performance of our capital programs. The total amount of exploration and development expenditures is managed as part of our budgeting process and can vary from period to period depending on the availability of adjusted funds flow and other sources of liquidity.

Free cash flow is not a measurement based on GAAP in Canada. We define free cash flow as adjusted funds flow less exploration and development expenditures (both non-GAAP measures discussed above), payments on lease obligations, and asset retirement obligations settled. Our determination of free cash flow may not be comparable to other issuers. We use free cash flow to evaluate funds available for debt repayment, common share repurchases, potential future dividends and acquisition and disposition opportunities.

Net debt is not a measurement based on GAAP in Canada. We define net debt to be the sum of cash, trade and other accounts receivable, trade and other accounts payable, and the principal amount of both the long-term notes and the credit facilities. Our definition of net debt may not be comparable to other issuers. We believe that this measure assists in providing a more complete understanding of our cash liabilities and provides a key measure to assess our liquidity. We use the principal amounts of the credit facilities and long-term notes outstanding in the calculation of net debt as these amounts represent our ultimate repayment obligation at maturity. The carrying amount of debt issue costs associated with the credit facilities and long-term notes is excluded on the basis that these amounts have already been paid by Baytex at inception of the contract and do not represent an additional source of capital or repayment obligation.

Operating netback is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. Operating netback is equal to petroleum and natural gas sales less blending expense, royalties, production and operating expense and transportation expense divided by barrels of oil equivalent sales volume for the applicable period. Our determination of operating netback may not be comparable with the calculation of similar measures for other entities. We believe that this measure assists in characterizing our ability to generate cash margin on a unit of production basis and is a key measure used to evaluate our operating performance.

Advisory Regarding Oil and Gas Information

Where applicable, oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

References herein to average 30-day initial production rates and other short-term production rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating aggregate production for us or the assets for which such rates are provided. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, we caution that the test results should be considered to be preliminary.

Throughout this news release, "oil and NGL" refers to heavy oil, bitumen, light and medium oil, tight oil, condensate and natural gas liquids ("NGL") product types as defined by NI 51-101. The following table shows Baytex's disaggregated production volumes for the three and nine months ended September 30, 2020. The NI 51-101 product types are included as follows: "Heavy Oil" - heavy oil and bitumen, "Light and Medium Oil" - light and medium oil, tight oil and condensate, "NGL" - natural gas liquids and "Natural Gas" - shale gas and conventional natural gas.

	Three Months Ended September 30, 2020					Nine Months Ended September 30, 2020				
	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada – Heavy										
Peace River	9,729	3	5	14,277	12,117	9,495	6	11	11,071	11,357
Lloydminster	12,409	12	—	1,518	12,674	11,451	13	—	1,280	11,677
Canada - Light										
Viking	—	16,943	105	10,357	18,774	—	19,047	108	11,398	21,054
Duvernay	—	710	457	1,840	1,474	—	690	385	1,535	1,330
Remaining Properties	—	580	714	16,988	4,125	—	653	674	17,743	4,284
United States										
Eagle Ford	—	15,853	6,136	39,965	28,650	—	19,161	6,446	45,574	33,203
Total	22,138	34,101	7,417	84,945	77,814	20,946	39,570	7,624	88,602	82,907

Baytex Energy Corp.

Baytex Energy Corp. is an oil and gas corporation based in Calgary, Alberta. The company is engaged in the acquisition, development and production of crude oil and natural gas in the Western Canadian Sedimentary Basin and in the Eagle Ford in the United States. Approximately 82% of Baytex's production is weighted toward crude oil and natural gas liquids. Baytex's common shares trade on the Toronto Stock Exchange under the symbol BTE and the New York Stock Exchange under the symbol BTE.BC.

For further information about Baytex, please visit our website at www.baytexenergy.com or contact:

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BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the three and nine months ended September 30, 2020 and 2019
Dated November 2, 2020

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three and nine months ended September 30, 2020. This information is provided as of November 2, 2020. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. The results for the three and nine months ended September 30, 2020 ("Q3/2020" and "YTD 2020") have been compared with the results for the three and nine months ended September 30, 2019 ("Q3/2019" and "YTD 2019"). This MD&A should be read in conjunction with the Company's condensed consolidated interim financial statements ("consolidated financial statements") for the three and nine months ended September 30, 2020, its audited comparative consolidated financial statements for the years ended December 31, 2019 and 2018, together with the accompanying notes, and its Annual Information Form for the year ended December 31, 2019. These documents and additional information about Baytex are accessible on the SEDAR website at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov. All amounts are in Canadian dollars, unless otherwise stated.

In this MD&A, barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil, which represents an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

This MD&A contains forward-looking information and statements along with certain measures which do not have any standardized meaning prescribed by Canadian Generally Accepted Accounting Principles ("GAAP"). The terms "adjusted funds flow", "operating netback", "exploration and development expenditures", "free cash flow", "net debt", and "Bank EBITDA" do not have any standardized meaning as prescribed by GAAP and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. We refer you to our advisory on forward-looking information and statements and a summary of our non-GAAP measures at the end of the MD&A.

BAYTEX ENERGY CORP.

Baytex Energy Corp. is a North American focused oil and gas company based in Calgary, Alberta. The company operates in Canada and the United States ("U.S"). The Canadian operating segment includes our light oil assets in the Viking and Duvernay, our heavy oil assets in Peace River and Lloydminster and our conventional oil and natural gas assets in Western Canada. The U.S. operating segment includes our Eagle Ford assets in Texas.

CURRENT ENVIRONMENT

In March 2020, the World Health Organization declared a global pandemic related to the novel coronavirus ("COVID-19"). The emergence of COVID-19 and the steps taken by governments to control the spread of the virus resulted in significant instability in the global economy and a sharp decline in demand for crude oil. This combined with the increased supply of crude oil due to the Russia and Saudi Arabia price war resulted in an unprecedented collapse in global crude oil prices and significant volatility during Q2/2020. Global crude oil prices began to recover and were relatively stable during Q3/2020 as members of OPEC+ agreed to production curtailments and governments began to ease restrictions that allowed economies to begin reopening which increased demand. While these factors have resulted in recent improvements in crude oil prices the outlook for prices remains uncertain due to the potential for additional government restrictions from COVID-19 and uncertainty that members of OPEC+ will maintain production curtailments.

We have taken significant action in response to the uncertain outlook for our industry. In March, we established a COVID-19 response team to coordinate, establish and implement our response measures which include restricted travel and adjusted work schedules. We have established remote working capabilities and procedures that will ensure business continuity as we continue to adhere to recommendations from applicable government and public health agencies. We have also taken steps to preserve our financial liquidity by reducing exploration and development expenditures and shutting in low margin production when operating netbacks were challenged. As a result of these actions we have maintained $425.8 million of availability on our credit facilities at September 30, 2020 and we are forecasting compliance with the financial covenants in our credit facilities at current forward prices.

The global health crisis surrounding COVID-19 has impacted our results for YTD 2020 and has resulted in uncertainty regarding the outlook and future performance of our industry. We do not know the extent and duration to which COVID-19 will impact demand and the price for oil. The overall effect on our business will depend on how quickly the world economy resumes activity which is highly dependent on the progression of the pandemic and the success of measures taken to prevent its spread.

THIRD QUARTER HIGHLIGHTS

Our financial and operating results for Q3/2020 reflect our response to the challenging market conditions caused by COVID-19. We delivered free cash flow of $59.9 million which allowed us to enhance our liquidity at Q3/2020 with $425.8 million available on our credit facilities. Production of 77,814 boe/d was in line with expectations and reflects limited development expenditures in the U.S. and minimal spending in Canada during Q2/2020 and Q3/2020. We reduced development activity in Canada and the U.S. following the decline in crude oil prices during March 2020 which resulted in total capital expenditures of $15.9 million for Q3/2020.

In Canada, production of 49,164 boe/d for Q3/2020 was consistent with expectations after we suspended development activity in March 2020. Development expenditures of $3.9 million for Q3/2020 were preliminary costs for Q4/2020 completion activity and land acquisition costs. Production of 49,164 boe/d for Q3/2020 was lower than 58,134 boe/d in Q3/2019 as a result of these actions.

In the U.S., we invested $12.0 million on exploration and development activity during Q3/2020 and drilled 22 (5.4 net) wells with 6 (0.8 net) wells brought on production. Production of 28,650 boe/d for Q3/2020 is consistent with expectations and reflects the suspension of completion activity during Q2/2020 along with a limited number of wells brought on production during Q3/2020. Completion activity was lower in Q3/2020 relative to Q3/2019 when we commenced production from 20 (4.6 net) wells and generated production of 36,793 boe/d in our U.S. operations.

Global benchmark prices for crude oil stabilized during Q3/2020 as the result of renewed production curtailments between members of the OPEC+ group and demand was partially restored after governments eased restrictions intended to limit the spread of COVID-19. Even with recent improvements the WTI benchmark price was 27% lower in Q3/2020 relative to Q3/2019 due to elevated global inventory levels and lower demand caused by the COVID-19 pandemic. The WTI benchmark price averaged US$40.93/bbl for Q3/2020 compared to US$56.45/bbl during Q3/2019.

Adjusted funds flow was $78.5 million in Q3/2020 compared to $213.4 million for Q3/2019. Our financial and operating results for Q3/2020 reflect our actions to reduce development activity during this period of low oil prices. Lower production combined with the decline in crude oil prices caused a $107.4 million decrease in operating netback relative to Q3/2019. The $133.1 million decrease in revenue, net of royalties and blending and other expense, was mitigated by our cost savings initiatives which resulted in a $29.7 million decrease in operating, transportation, and general and administrative expenses for Q3/2020 compared to Q3/2019. We also recorded realized financial derivative losses of $9.7 million in Q3/2020 compared to gains of $20.9 million in Q3/2019. We recorded net loss of $23.4 million for Q3/2020 compared to net income of $15.2 million in Q3/2019 which reflects the decrease in adjusted funds flow partially offset by lower depletion in Q3/2020 relative to Q3/2019.

Net debt was $1.91 billion at September 30, 2020 compared to $1.87 billion at December 31, 2019. We generated free cash flow of $16.3 million during YTD 2020 and we had $425.8 million available on our credit facilities at September 30, 2020. The reduction in net debt from free cash flow was offset by total transaction and financing costs of $17.6 million related to the refinancing transactions in Q1/2020 in addition to a $30.9 million increase in the reported amount of our U.S. dollar denominated net debt due to a weaker Canadian dollar at September 30, 2020 compared to December 31, 2019.

2020 GUIDANCE

Our results for YTD 2020 are consistent with expectations and are in line with our annual guidance released on June 25, 2020. Production for YTD 2020 exceeded our annual guidance while exploration and development expenditures are expected to fall within our annual guidance range. We have revised our annual guidance for 2020 which reflects our cost savings initiatives and efforts to optimize our operations in response to lower crude oil prices.

The following table compares our updated 2020 guidance to our previously announced guidance and our YTD 2020 results.

	Previous Annual Guidance (1)	Revised Annual Guidance	YTD 2020 Results
Exploration and development expenditures ($ millions)	$260 - $290	no change	$202.5
Production (boe/d)	78,000 - 82,000	~80,000	82,907
Expenses:			
Royalty rate (%)	~18.5	~18.0	17.9
Operating ($/boe)	$11.75 - $12.50	$11.20 - $11.40	$11.08
Transportation ($/boe)	$0.95 - $1.05	no change	$0.96
General and administrative ($ millions)	$38 ($1.30/boe)	no change	$25.0 ($1.10/boe)
Cash interest ($ millions)	$112 ($3.84/boe)	$108 ($3.70/boe)	$81.3 ($3.58/boe)
Leasing expenditures ($ millions)	$7	$6	$4.4
Asset retirement obligations ($ millions)	$10	$8	$6.1

(1) As announced on June 25, 2020.

RESULTS OF OPERATIONS

The Canadian operating segment includes our light oil assets in Viking and Duvernay, our heavy oil assets in Peace River and Lloydminster and our conventional oil and natural gas assets in Western Canada. The U.S. operating segment includes our Eagle Ford assets in Texas.

Production

	Three Months Ended September 30					
	2020			2019		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**18,248**	**15,853**	**34,101**	22,493	20,336	42,829
Heavy oil	**22,138**	**—**	**22,138**	25,712	—	25,712
Natural Gas Liquids (NGL)	**1,281**	**6,136**	**7,417**	1,575	7,968	9,543
Total liquids (bbl/d)	**41,667**	**21,989**	**63,656**	49,780	28,304	78,084
Natural gas (mcf/d)	**44,980**	**39,965**	**84,945**	50,122	50,932	101,054
Total production (boe/d)	**49,164**	**28,650**	**77,814**	58,134	36,793	94,927
Production Mix						
Segment as a percent of total	**63 %**	**37 %**	**100 %**	61 %	39 %	100 %
Light oil and condensate	**37 %**	**55 %**	**44 %**	39 %	55 %	45 %
Heavy oil	**45 %**	**— %**	**28 %**	44 %	— %	27 %
NGL	**3 %**	**22 %**	**10 %**	3 %	22 %	10 %
Natural gas	**15 %**	**23 %**	**18 %**	14 %	23 %	18 %

	Nine Months Ended September 30					
	2020			2019		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**20,409**	**19,161**	**39,570**	22,636	20,843	43,479
Heavy oil	**20,946**	**—**	**20,946**	26,637	—	26,637
Natural Gas Liquids (NGL)	**1,178**	**6,446**	**7,624**	1,430	9,315	10,745
Total liquids (bbl/d)	**42,533**	**25,607**	**68,140**	50,703	30,158	80,861
Natural gas (mcf/d)	**43,028**	**45,574**	**88,602**	49,207	54,380	103,587
Total production (boe/d)	**49,704**	**33,203**	**82,907**	58,904	39,221	98,125
Production Mix						
Segment as a percent of total	**60 %**	**40 %**	**100 %**	60 %	40 %	100 %
Light oil and condensate	**41 %**	**58 %**	**48 %**	39 %	53 %	44 %
Heavy oil	**42 %**	**— %**	**25 %**	45 %	— %	27 %
NGL	**2 %**	**19 %**	**9 %**	2 %	24 %	11 %
Natural gas	**15 %**	**23 %**	**18 %**	14 %	23 %	18 %

Production was 77,814 boe/d for Q3/2020 and 82,907 boe/d for YTD 2020 compared to 94,927 boe/d for Q3/2019 and 98,125 boe/d for YTD 2019. Our production results for Q3/2020 and YTD 2020 were in line with expectations and are a result of lower development activity in Canada and the U.S. following the sharp decline in crude oil prices in March 2020.

In Canada, production was 49,164 boe/d for Q3/2020 and 49,704 boe/d for YTD 2020 compared to 58,134 boe/d for Q3/2019 and 58,904 boe/d for YTD 2019. Lower production in both periods of 2020 is a result of lower development activity relative to the comparative periods of 2019 as we suspended our Canadian development program and temporarily shut-in production in response to the sharp decline in crude oil prices in March 2020.

Production in the U.S. was 28,650 boe/d for Q3/2020 and 33,203 boe/d for YTD 2020 compared to 36,793 boe/d for Q3/2019 and 39,221 boe/d for YTD 2019. U.S. production was lower for both periods of 2020 which reflects lower completion activity during Q3/2020 and YTD 2020 relative to the same periods of 2019. We initiated production from 6 (0.8 net) wells during Q3/2020 and 53 (11.5 net) wells during YTD 2020 compared to 20 (4.6 net) in Q3/2019 and 85 (18.6 net) wells in YTD 2019.

Our annual guidance of approximately 80,000 boe/d reflects optimized production levels and development activity in Canada and the U.S.

Commodity Prices

The prices received for our crude oil and natural gas production directly impact our earnings, adjusted funds flow and our financial position.

Crude Oil

Global benchmark prices for crude oil were relatively strong leading into 2020 as stable demand and production outlooks continued from Q4/2019. Benchmark prices began to decline rapidly in March after members of the OPEC+ group began to increase the supply of crude oil to the global market and measures to limit the spread of COVID-19 resulted in a significant decrease in the demand for crude oil. Global benchmark prices began to improve in July 2020 and were relatively stable throughout Q3/2020 following the OPEC+ decision to reinstate supply cuts along with improved demand after measures intended to limit the spread of COVID-19 were relaxed.

We compare the price received for our U.S. crude oil production to the Magellan East Houston ("MEH") stream at Houston, Texas which is a representative benchmark for light oil pricing at the U.S. Gulf coast. The MEH benchmark averaged US$41.63/bbl during Q3/2020 and US$39.19/bbl during YTD 2020 compared to US$61.07/bbl during Q3/2019 and US$62.63/bbl during YTD 2019. The MEH benchmark was at a US$0.70/bbl and US$0.87/bbl premium to WTI in Q3/2020 and YTD 2020 compared to a US$4.62/bbl and US$5.57/bbl premium to WTI during Q3/2019 and YTD 2019. The decrease in the MEH benchmark premium to WTI in 2020 was a result of elevated inventory levels as a result of lower refinery demand on the U.S. Gulf coast relative to both periods in 2019.

Prices for Canadian oil trade at a discount to WTI due to a lack of egress to diversified markets from Western Canada. Canadian light and heavy oil differentials to WTI were wider in early 2020 relative to 2019 as a result of higher Canadian oil production. Canadian oil differentials narrowed with production shut-ins in Western Canada during Q2/2020 and resulted in light and heavy oil differentials for Q3/2020 that were US$1.15/bbl and US$3.15/bbl narrower relative to Q3/2019 respectively.

We compare the price received for our light oil production in Canada to the Edmonton par benchmark oil price which is the representative benchmark for light grades of crude oil in Western Canada. The Edmonton par price averaged $49.83/bbl during Q3/2020 and $43.70/bbl during YTD 2020 compared to $68.41/bbl during Q3/2019 and $69.59/bbl during YTD 2019. Edmonton par traded at a discount to WTI of US$3.51/bbl for Q3/2020 and US$6.04/bbl for YTD 2020 compared to a discount of US$4.66/bbl for Q3/2019 and US$4.70/bbl for YTD 2019.

The price received for our heavy oil production in Canada is based on the WCS benchmark price which is the representative benchmark for heavy grades of crude oil in Western Canada. The WCS heavy oil price averaged $42.40/bbl for Q3/2020 and $33.34/bbl for YTD 2020 as compared to $58.39/bbl for Q3/2019 and $60.24/bbl for YTD 2019. The WCS heavy oil differential was US$9.09/bbl in Q3/2020 and US$13.70/bbl in YTD 2020 compared to US$12.24/bbl for Q3/2019 and US$11.74/bbl for YTD 2019.

Natural Gas

U.S. natural gas prices for Q3/2020 and YTD 2020 were lower than Q3/2019 and YTD 2019 as U.S. natural gas inventory levels remained elevated due to lower demand despite falling natural gas production. Canadian natural gas prices improved in Q3/2020 and YTD 2020 due to lower associated gas production as a result of oil production being shut-in in Western Canada during 2020.

Our U.S. natural gas production is priced in reference to the New York Mercantile Exchange ("NYMEX") natural gas index. The NYMEX natural gas benchmark averaged US$1.98/mmbtu in Q3/2020 and US$1.88/mmbtu in YTD 2020 which is lower than US$2.23/mmbtu in Q3/2019 and US$2.67/mmbtu in YTD 2019. Record U.S. natural gas production levels leading into 2020 resulted in an oversupplied North American market and lower natural gas prices in YTD 2020 relative to YTD 2019.

In Canada, we receive natural gas pricing based on the AECO benchmark which continues to trade at a discount to NYMEX as a result of increasing supply and limited market access for Canadian natural gas production. The AECO benchmark averaged $2.18/mcf during Q3/2020 and $2.08/mcf during YTD 2020 which is higher than $1.04/mcf for Q3/2019 and $1.39/mcf for YTD 2019. The AECO gas benchmark was higher in both periods of 2020 relative to 2019 due to lower associated gas production from oil production that was shut-in in Western Canada during both periods of 2020.

The following tables compare select benchmark prices and our average realized selling prices for the three and nine months ended September 30, 2020 and 2019.

	Three Months Ended September 30			Nine Months Ended September 30		
	2020	2019	Change	**2020**	2019	Change
Benchmark Averages						
WTI oil (US$/bbl)[1]	**40.93**	56.45	(15.52)	**38.32**	57.06	(18.74)
MEH oil (US$/bbl)[2]	**41.63**	61.07	(19.44)	**39.19**	62.63	(23.44)
MEH oil differential to WTI (US$/bbl)	**0.70**	4.62	(3.92)	**0.87**	5.57	(4.70)
Edmonton par oil ($/bbl)	**49.83**	68.41	(18.58)	**43.70**	69.59	(25.89)
Edmonton par oil differential to WTI (US$/bbl)	**(3.51)**	(4.66)	1.15	**(6.04)**	(4.70)	(1.34)
WCS heavy oil ($/bbl)[3]	**42.40**	58.39	(15.99)	**33.34**	60.24	(26.90)
WCS heavy oil differential to WTI (US$/bbl)	**(9.09)**	(12.24)	3.15	**(13.70)**	(11.74)	(1.96)
AECO natural gas price ($/mcf)[4]	**2.18**	1.04	1.14	**2.08**	1.39	0.69
NYMEX natural gas price (US$/mmbtu)[5]	**1.98**	2.23	(0.25)	**1.88**	2.67	(0.79)
CAD/USD average exchange rate	**1.3316**	1.3207	0.0109	**1.3541**	1.3292	0.0249

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.
(2) MEH refers to arithmetic average of the Argus WTI Houston differential weighted index price for the applicable period.
(3) WCS refers to the average posting price for the benchmark WCS heavy oil.
(4) AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter ("CGPR").
(5) NYMEX refers to the NYMEX last day average index price as published by the CGPR.

	Three Months Ended September 30					
	2020			2019		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl)	**$ 46.72**	**$ 51.85**	**$ 49.10**	$ 65.20	$ 75.01	$ 69.86
Heavy oil ($/bbl)[1]	**29.03**	**—**	**29.03**	44.39	—	44.39
NGL ($/bbl)	**14.95**	**15.79**	**15.65**	10.26	15.07	14.27
Natural gas ($/mcf)	**2.14**	**2.50**	**2.31**	0.95	3.08	2.03
Weighted average ($/boe)[1]	**$ 32.76**	**$ 35.55**	**$ 33.79**	$ 45.96	$ 48.99	$ 47.14

	Nine Months Ended September 30					
	2020			2019		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl)	**$ 41.08**	**$ 49.11**	**$ 44.97**	$ 66.20	$ 77.81	$ 71.77
Heavy oil ($/bbl)[1]	**23.03**	**—**	**23.03**	45.53	—	45.53
NGL ($/bbl)	**12.27**	**14.60**	**14.24**	17.12	18.74	18.52
Natural gas ($/mcf)	**2.01**	**2.50**	**2.26**	1.49	3.51	2.55
Weighted average ($/boe)[1]	**$ 28.60**	**$ 34.61**	**$ 31.01**	$ 47.69	$ 50.67	$ 48.88

(1) Realized heavy oil prices are calculated based on sales volumes and sales dollars, net of blending and other expense.

Average Realized Sales Prices

Our weighted average sales price was $33.79/boe for Q3/2020 and $31.01/boe for YTD 2020 compared to $47.14/boe for Q3/2019 and $48.88/boe for YTD 2019. Our realized price in the U.S. was $35.55/boe in Q3/2020 which is $13.44/boe lower than $48.99/boe in Q3/2019. In Canada, our realized price of $32.76/boe for Q3/2020 was $13.20/boe lower than $45.96/boe for Q3/2019. The decrease in our realized price in Canada and the U.S. for both periods of 2020 were a result of the decrease in North American benchmark prices relative to the comparatives periods of 2019.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Our realized light oil and condensate price was $46.72/bbl in Q3/2020 and $41.08/bbl in YTD 2020 compared to $65.20/bbl in Q3/2019 and $66.20/bbl in YTD 2019. Our realized light oil and condensate price for Q3/2020 and YTD 2020 represents a discount of $3.11/bbl and $2.62/bbl respectively to the Edmonton par price which is relatively consistent with discounts of $3.21/bbl in Q3/2019 and $3.39/bbl in YTD 2019. The discount of $3.11/bbl for Q3/2020 reflects fluctuations in regional pricing for our Viking light oil production relative to the Edmonton par benchmark and is consistent with our expectations to receive a $2.50/bbl to $3.50/bbl discount to the Edmonton par price for the second half of 2020. Our YTD 2020 discount of $2.62/bbl to the Edmonton par price reflects improved price realizations on our light oil production relative to YTD 2019 when our discount to the Edmonton par price was $3.39/bbl.

We compare the price received for our U.S. light oil and condensate production to the MEH benchmark. Our realized light oil and condensate price averaged $51.85/bbl for Q3/2020 and $49.11/bbl for YTD 2020 compared to $75.01/bbl for Q3/2019 and $77.81/bbl for YTD 2019. Expressed in U.S. dollars, our realized light oil and condensate price of US$38.94/bbl for Q3/2020 and US$36.27/bbl for YTD 2020 represents a US$2.69/bbl discount to MEH for Q3/2020 and a discount of US$2.92/bbl for YTD 2020. A change in marketing contracts during Q3/2019 resulted in improved price realizations for both periods of 2020 relative to Q3/2019 and YTD 2019 when our discount to MEH was US$4.27/bbl and US$4.09/bbl, respectively.

Our realized heavy oil price, net of blending and other expense averaged $29.03/bbl in Q3/2020 and $23.03/bbl in YTD 2020 compared to $44.39/bbl in Q3/2019 and $45.53/bbl in YTD 2019. Our realized heavy oil price for Q3/2020 and YTD 2020 was $15.36/bbl and $22.50/bbl lower relative to Q3/2019 and YTD 2019 respectively compared to a $15.99/bbl and $26.90/bbl decrease in the WCS benchmark price over the same periods. Our realized heavy oil price did not decrease as much as WCS benchmark pricing as we optimized production levels and the timing of deliveries during 2020 which achieved stronger price realizations.

Our realized NGL price as a percentage of WTI can vary from period to period based on the product mix of our NGL volumes and changes in the market prices for the underlying products. Our realized NGL price was $15.65/bbl in Q3/2020 or 29% of WTI (expressed in Canadian dollars) compared to $14.27/bbl or 19% of WTI (expressed in Canadian dollars) in Q3/2019. Our YTD 2020 realized NGL price was $14.24/bbl or 27% of WTI (expressed in Canadian dollars) compared to $18.52/bbl or 24% of WTI (expressed in Canadian dollars) in YTD 2019. Our realized NGL price was higher as a percentage of WTI in Q3/2020 and YTD 2020 relative to the same periods of 2019 as the decrease in the underlying product prices wasn't as large relative to the decrease in WTI over the same period.

We compare our realized natural gas price in Canada to the AECO benchmark price. Our realized natural gas price was $2.14/mcf for Q3/2020 and $2.01/mcf in YTD 2020 compared to $0.95/mcf in Q2/2019 and $1.49/mcf in YTD 2019. The increase in our realized natural gas price in Canada is consistent with the increase in the AECO benchmark price over the same periods. In the U.S., our realized natural gas price was US$1.88/mcf for Q3/2020 and US$1.85/mcf in YTD 2020 compared to US$2.33/mcf in Q3/2019 and US$2.64/mcf in YTD 2019. Our realized natural gas price in the U.S. is consistent with the NYMEX benchmark in both periods of 2020 and 2019.

Petroleum and Natural Gas Sales

	Three Months Ended September 30					
	2020			2019		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 78,432**	**$ 75,620**	**$ 154,052**	$ 134,921	$ 140,344	$ 275,265
Heavy oil	**69,791**	**—**	**69,791**	117,961	—	117,961
NGL	**1,762**	**8,914**	**10,676**	1,486	11,045	12,531
Total oil sales	**149,985**	**84,534**	**234,519**	254,368	151,389	405,757
Natural gas sales	**8,846**	**9,173**	**18,019**	4,401	14,442	18,843
Total petroleum and natural gas sales	**158,831**	**93,707**	**252,538**	258,769	165,831	424,600
Blending and other expense	**(10,673)**	**—**	**(10,673)**	(12,950)	—	(12,950)
Total sales, net of blending and other expense	**$ 148,158**	**$ 93,707**	**$ 241,865**	$ 245,819	$ 165,831	$ 411,650

	Nine Months Ended September 30					
	2020			2019		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 229,745**	**$ 257,818**	**$ 487,563**	$ 409,117	$ 442,763	$ 851,880
Heavy oil	**169,638**	**—**	**169,638**	381,684	—	381,684
NGL	**3,957**	**25,791**	**29,748**	6,684	47,656	54,340
Total oil sales	**403,340**	**283,609**	**686,949**	797,485	490,419	1,287,904
Natural gas sales	**23,660**	**31,232**	**54,892**	20,021	52,099	72,120
Total petroleum and natural gas sales	**427,000**	**314,841**	**741,841**	817,506	542,518	1,360,024
Blending and other expense	**(37,490)**	**—**	**(37,490)**	(50,628)	—	(50,628)
Total sales, net of blending and other expense	**$ 389,510**	**$ 314,841**	**$ 704,351**	$ 766,878	$ 542,518	$ 1,309,396

Total sales, net of blending and other expense, of $241.9 million for Q3/2020 decreased $169.8 million from $411.7 million reported for Q3/2019 while total sales, net of blending and other expense, of $704.4 million for YTD 2020 decreased $605.0 million from $1,309.4 million in YTD 2019. The decrease in total sales in both periods of 2020 is a result of lower realized pricing from the decrease in benchmark pricing along with lower production relative to the comparative periods of 2019.

In Canada, total sales, net of blending and other expense, was $148.2 million for Q3/2020 which is a decrease of $97.7 million from Q3/2019. Total petroleum and natural gas sales decreased due lower realized pricing combined with lower production in Q3/2020 relative to Q3/2019. Lower pricing in Q3/2020 resulted in a $59.7 million decrease in total sales, net of blending and other expense and lower production contributed a $37.9 million decrease in total sales, net of blending and other expense relative to Q3/2019. Lower production and the decrease in benchmark prices resulted in our total sales, net of blending and other expense, decreasing to $389.5 million in YTD 2020 from $766.9 million in YTD 2019.

In the U.S., petroleum and natural gas sales were $93.7 million for Q3/2020 which is a decrease of $72.1 million from $165.8 million reported for Q3/2019. Lower pricing in Q3/2020 resulted in a $35.4 million decrease in total petroleum and natural gas sales while lower production contributed a $36.7 million decrease in total petroleum and natural gas sales relative to Q3/2019. Lower production and realized pricing in YTD 2020 resulted in petroleum and natural gas sales of $314.8 million which was $227.7 million lower than $542.5 million for YTD 2019.

Royalties

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues or on operating netbacks less capital investment for specific heavy oil projects, and are generally expressed as a percentage of total sales, net of blending and other expense. The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction. The following table summarizes our royalties and royalty rates for the three and nine months ended September 30, 2020 and 2019.

	Three Months Ended September 30					
	2020			2019		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 12,297**	**$ 27,755**	**$ 40,052**	$ 26,193	$ 48,824	$ 75,017
Average royalty rate(1)	**8.3 %**	**29.6 %**	**16.6 %**	10.7 %	29.4 %	18.2 %
Royalties per boe	**$ 2.72**	**$ 10.53**	**$ 5.59**	$ 4.90	$ 14.42	$ 8.59

	Nine Months Ended September 30					
	2020			2019		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 33,972**	**$ 91,956**	**$ 125,928**	$ 82,313	$ 160,646	$ 242,959
Average royalty rate(1)	**8.7 %**	**29.2 %**	**17.9 %**	10.7 %	29.6 %	18.6 %
Royalties per boe	**$ 2.49**	**$ 10.11**	**$ 5.54**	$ 5.12	$ 15.00	$ 9.07

(1) Average royalty rate is calculated as royalties divided by total sales, net of blending and other expense.

Royalties for Q3/2020 were $40.1 million or 16.6% of total sales, net of blending and other expense compared to $75.0 million or 18.2% in Q3/2019. Total royalties in YTD 2020 were $125.9 million or 17.9% of total sales, net of blending and other expense compared to $243.0 million or 18.6% in YTD 2019. Total royalty expense is lower in Q3/2020 and YTD 2020 due to lower total sales, net of blending and other expense, relative to the same periods of 2019. Our royalty rate of 16.6% for Q3/2020 was lower than 18.2% for Q3/2019 as a higher proportion of our total sales, net of blending and other expense, were from our Canadian properties in Q3/2020 relative to the same period of 2019. Our royalty rate of 17.9% for YTD 2020 was slightly lower 18.6% in YTD 2019 due to a lower royalty rate on our Canadian properties as a result of lower commodity prices.

Our Canadian royalty rate of 8.3% for Q3/2020 and 8.7% for YTD 2020 was lower than 10.7% for Q3/2019 and 10.7% for YTD 2019 due to lower benchmark commodity prices which resulted in a lower royalty rate on our Canadian properties in 2020 relative to 2019. In the U.S., royalties averaged 29.6% for Q3/2020 and 29.2% YTD 2020 of total sales which is consistent with the same periods of 2019 as the royalty rate on our U.S. production does not vary with price but can vary across our acreage.

Our average royalty rate of 17.9% for YTD 2020 is consistent with expectations and our annual guidance of approximately 18.0% for 2020.

Operating Expense

	Three Months Ended September 30					
	2020			2019		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 57,557**	**$ 15,890**	**$ 73,447**	$ 73,701	$ 23,676	$ 97,377
Operating expense per boe	**$ 12.73**	**$ 6.03**	**$ 10.26**	$ 13.78	$ 6.99	$ 11.15

	Nine Months Ended September 30					
	2020			2019		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 185,641**	**$ 65,956**	**$ 251,597**	$ 221,680	$ 76,463	$ 298,143
Operating expense per boe	**$ 13.63**	**$ 7.25**	**$ 11.08**	$ 13.79	$ 7.14	$ 11.13

Operating expense was $73.4 million ($10.26/boe) for Q3/2020 and $251.6 million ($11.08/boe) for YTD 2020 compared to $97.4 million ($11.15/boe) in Q3/2019 and $298.1 million ($11.13/boe) in YTD 2019. The decrease in total operating expense can be attributed to a decrease in production in addition to our cost savings initiatives which resulted in per boe operating expense for Q3/2020 and YTD 2020 which was slightly lower than the comparative periods of 2019.

In Canada, operating expense was $57.6 million ($12.73/boe) for Q3/2020 and $185.6 million ($13.63/boe) for YTD 2020 compared to $73.7 million ($13.78/boe) for Q3/2019 and $221.7 million ($13.79/boe) in YTD 2019. Total operating expense in Canada has decreased with lower production in both periods of 2020 compared to 2019. Per unit operating expense of $12.73/boe for Q3/2020 and $13.63/boe for YTD 2020 was lower than the comparative periods of 2019 due to our cost savings initiatives in addition to shutting in certain high operating cost, low margin properties for a portion of 2020.

U.S. operating expense was $15.9 million ($6.03/boe) for Q3/2020 and $66.0 million ($7.25/boe) for YTD 2020 compared to $23.7 million ($6.99/boe) for Q3/2019 and $76.5 million ($7.14/boe) in YTD 2019. Lower total operating expense is primarily a result of lower U.S. production in Q3/2020 and YTD 2020 relative to the comparative periods of 2019. Expressed in U.S. dollars, per unit operating expense was US$4.53/boe in Q3/2020 and US$5.35/boe in YTD 2020 which is lower than US$5.29/boe for Q3/2019 and US$5.37/boe in YTD 2019. During Q3/2020, we received a $3.7 million reimbursement of prior period charges from the operator of our Eagle Ford properties which resulted in lower total and per unit operating expense for Q3/2020.

Operating expense of $11.08/boe for YTD 2020 is consistent with our expectations and slightly below our annual guidance range of $11.20 - $11.40/boe for 2020.

Transportation Expense

Transportation expense includes the costs to move production from the field to the sales point. The largest component of transportation expense relates to the trucking of oil in Canada to pipeline and rail terminals which can vary from period to period depending on hauling distances as we seek to optimize sales prices and trucking rates. The following table compares our transportation expense for the three and nine months ended September 30, 2020 and 2019.

	Three Months Ended September 30					
	2020			2019		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 6,372**	**$ —**	**$ 6,372**	$ 9,903	$ —	$ 9,903
Transportation expense per boe	**$ 1.41**	**$ —**	**$ 0.89**	$ 1.85	$ —	$ 1.13

	Nine Months Ended September 30					
	2020			2019		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 21,745**	**$ —**	**$ 21,745**	$ 35,102	$ —	$ 35,102
Transportation expense per boe	**$ 1.60**	**$ —**	**$ 0.96**	$ 2.18	$ —	$ 1.31

Transportation expense was $6.4 million ($0.89/boe) for Q3/2020 and $21.7 million ($0.96/boe) for YTD 2020 compared to $9.9 million ($1.13/boe) in Q3/2019 and $35.1 million ($1.31/boe) in YTD 2019. The decrease in total transportation expense in both periods of 2020 relative to 2019 is primarily the result of lower crude oil shipments due to lower light and heavy oil production in Canada. Optimization of light and heavy oil deliveries in Canada resulted in lower per boe transportation expense for both periods of 2020 relative to the same periods of 2019. Transportation expense of $0.96 per boe for YTD 2020 is consistent with expectations and is at the low end of our annual guidance of $0.95 to $1.05 per boe for 2020.

Blending and Other Expense

Blending and other expense primarily includes the cost of blending diluent purchased to reduce the viscosity of our heavy oil transported through pipelines in order to meet pipeline specifications. The purchased diluent is recorded as blending and other expense. The price received for the blended product is recorded as heavy oil sales revenue. We net blending and other expense against heavy oil sales to compare the realized price on our produced volumes to benchmark pricing.

Blending and other expense was $10.7 million for Q3/2020 and $37.5 million for YTD 2020 compared to $13.0 million for Q3/2019 and $50.6 million for YTD 2019. Lower blending and other expense in both periods of 2020 compared to 2019 reflects lower heavy oil sales as we shut in heavy oil production in addition to a decrease in the per unit cost of blending diluent during YTD 2020.

Financial Derivatives

As part of our normal operations, we are exposed to movements in commodity prices, foreign exchange rates and interest rates. In an effort to manage these exposures, we utilize various financial derivative contracts which are intended to partially reduce the volatility in our adjusted funds flow. Contracts settled in the period result in realized gains or losses based on the market price compared to the contract price and the notional volume outstanding. Changes in the fair value of unsettled contracts are reported as unrealized gains or losses in the period as the forward markets for commodities and currencies fluctuate and as new contracts are executed. The following table summarizes the results of our financial derivative contracts for the three and nine months ended September 30, 2020 and 2019.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2020**	2019	Change	**2020**	2019	Change
Realized financial derivatives gain (loss)						
Crude oil	**$ (9,530)**	$ 19,631	$ (29,161)	**$ 30,640**	$ 49,944	$ (19,304)
Natural gas	**165**	1,243	(1,078)	**753**	2,713	(1,960)
Interest and financing	**(378)**	(17)	(361)	**(662)**	7	(669)
Total	**$ (9,743)**	$ 20,857	$ (30,600)	**$ 30,731**	$ 52,664	$ (21,933)
Unrealized financial derivatives gain (loss)						
Crude oil	**$ (717)**	$ 8,559	$ (9,276)	**$ 27,155**	$ (29,083)	$ 56,238
Natural gas	**(6,885)**	(1,041)	(5,844)	**(5,826)**	(1,391)	(4,435)
Interest and financing	**372**	148	224	**(101)**	(448)	347
Equity total return swap ("Equity TRS")	**(54)**	—	(54)	**(1,803)**	—	(1,803)
Total	**$ (7,284)**	$ 7,666	$ (14,950)	**$ 19,425**	$ (30,922)	$ 50,347
Total financial derivatives gain (loss)						
Crude oil	**$ (10,247)**	$ 28,190	$ (38,437)	**$ 57,795**	$ 20,861	$ 36,934
Natural gas	**(6,720)**	202	(6,922)	**(5,073)**	1,322	(6,395)
Interest and financing	**(6)**	131	(137)	**(763)**	(441)	(322)
Equity TRS	**(54)**	—	(54)	**(1,803)**	—	(1,803)
Total	**$ (17,027)**	$ 28,523	$ (45,550)	**$ 50,156**	$ 21,742	$ 28,414

We recorded total financial derivative losses of $17.0 million for Q3/2020 and gains of $50.2 million for YTD 2020. Realized financial derivative gains and losses were primarily driven by settlements on our crude oil contracts and we recorded realized losses of $9.7 million for Q3/2020 and realized gains of $30.7 million for YTD 2020. The unrealized loss of $7.3 million for Q3/2020 and the unrealized gain of $19.4 million for YTD 2020 is primarily due to fluctuations in future commodity prices and revaluation of contracts in place at September 30, 2020 compared to the value of contracts in place at the start of the respective periods.

During Q2/2020, we entered into short-term crude oil financial derivative contracts to provide price certainty for restarting production in our Canadian operations. These contracts were the primary reason for realized losses of $9.5 million in Q3/2020 as market prices for crude oil recovered from Q2/2020 lows and settled at levels above the prices set in these contracts. Realized gains on crude oil financial derivatives of $30.6 million in YTD 2020 are primarily a result of market prices for WTI settling at levels below the prices set in our contracts outstanding during the period.

Unrealized losses of $7.3 million in Q3/2020 and gains of $19.4 million for YTD 2020 reflect the volatility in forecasted gas and crude oil pricing used to revalue our contracts in place at September 30, 2020 relative to June 30, 2020 and December 31, 2019 along with the valuation of new contracts entered during the period. Forecasted crude oil prices at September 30, 2020 were relatively consistent with June 30, 2020 and lower relative to December 31, 2019. Forecasted gas prices at September 30, 2020 were higher relative to June 30, 2020 and December 31, 2019. The fair value of our financial derivative contracts resulted in a net asset of $16.2 million at September 30, 2020 compared to a net asset of $23.5 million at June 30, 2020 and a net liability of $3.2 million at December 31, 2019.

We had the following commodity financial derivative contracts as at November 2, 2020.

	Period	Volume	Price/Unit[1]	Index
Oil				
Basis Swap	Oct 2020 to Dec 2020	6,500 bbl/d	WTI less US$16.27/bbl	WCS
Basis Swap	Jan 2021 to Jun 2021	2,000 bbl/d	WTI less US$13.75/bbl	WCS
Basis Swap	Jan 2021 to Dec 2021	4,000 bbl/d	WTI less US$14.26/bbl	WCS
Basis Swap[6]	Jan 2021 to Dec 2021	2,000 bbl/d	WTI less US$13.41/bbl	WCS
Basis Swap	Oct 2020 to Dec 2020	5,000 bbl/d	WTI less US$6.15/bbl	MSW
Basis Swap	Jan 2021 to Dec 2021	2,000 bbl/d	WTI less US$5.95/bbl	MSW
Basis Swap[6]	Jan 2021 to Dec 2021	4,000 bbl/d	WTI less US$4.78/bbl	MSW
Fixed - Sell	Oct 2020 to Dec 2020	8,000 bbl/d	US$42.78/bbl	WTI
3-way option[2]	Oct 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$56.00/US$61.35	WTI
3-way option[2]	Oct 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$57.00/US$60.00	WTI
3-way option[2]	Oct 2020 to Dec 2020	4,500 bbl/d	US$50.00/US$57.00/US$62.00	WTI
3-way option[2]	Oct 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$58.00/US$62.00	WTI
3-way option[2]	Oct 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$58.00/US$60.50	WTI
3-way option[2]	Oct 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$58.00/US$60.83	WTI
3-way option[2]	Oct 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$65.60	WTI
3-way option[2]	Oct 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$66.00	WTI
3-way option[2]	Oct 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$59.50/US$66.15	WTI
3-way option[2]	Oct 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$65.60	WTI
3-way option[2]	Oct 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.00	WTI
3-way option[2]	Oct 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.05	WTI
3-way option[2]	Oct 2020 to Dec 2020	2,000 bbl/d	US$51.00/US$60.00/US$66.70	WTI
3-way option[2]	Jan 2021 to Dec 2021	3,500 bbl/d	US$35.00/US$45.00/US$49.50	WTI
3-way option[2]	Jan 2021 to Dec 2021	10,000 bbl/d	US$35.00/US$45.00/US$55.00	WTI
Swaption[3]	Jan 2021 to Dec 2021	3,000 bbl/d	US$70.00/bbl	Brent
Swaption[3]	Jan 2021 to Dec 2021	3,000 bbl/d	US$60.75/bbl	WTI
Swaption[5]	Jan 2022 to Dec 2022	5,000 bbl/d	US$53.00/bbl	WTI
Swaption[5]	Jan 2022 to Dec 2022	5,000 bbl/d	US$54.00/bbl	WTI
Natural Gas				
Fixed - Sell	Oct 2020 to Dec 2020	10,500 GJ/d	$2.01/GJ	AECO 7A
Fixed - Sell	Jan 2021 to Jun 2021	3,000 GJ/d	$2.71/GJ	AECO 7A
Fixed - Sell	Jan 2021 to Dec 2021	16,000 GJ/d	$2.36/GJ	AECO 7A
Fixed - Sell	Oct 2020 to Dec 2020	2,500 GJ/d	$2.29/GJ	AECO 5A
Fixed - Sell	Jan 2021 to Dec 2021	2,500 GJ/d	$2.40/GJ	AECO 5A
Fixed - Sell	Oct 2020 to Dec 2020	5,500 mmbtu/d	US$2.64/mmbtu	NYMEX
Fixed - Sell	Jan 2021 to Dec 2021	12,000 mmbtu/d	US$2.70/mmbtu	NYMEX
3-way option[2]	Oct 2020 to Dec 2020	5,000 mmbtu/d	US$2.25/US$2.60/US$2.85	NYMEX
3-way option[2][6]	Jan 2022 to Dec 2022	2,500 mmbtu/d	US$2.25/US$2.75/US$3.06	NYMEX
Swaption[4]	Jan 2021 to Dec 2021	5,000 mmbtu/d	US$2.90/mmbtu	NYMEX

(1) Based on the weighted average price per unit for the period.

(2) Producer 3-way option consists of a sold put, a bought put and a sold call. To illustrate, in a US$50.00/US$58.00/US$62.00 contract, Baytex receives WTI plus US$8.00/bbl when WTI is at or below US$50.00/bbl; Baytex receives US$58.00/bbl when WTI is between US$50.00/bbl and US$58.00/bbl; Baytex receives the market price when WTI is between US$58.00/bbl and US$62.00/bbl; and Baytex receives US$62.00/bbl when WTI is above US$62.00/bbl.

(3) For these contracts, the counterparty has the right, if exercised on December 31, 2020, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.

(4) For these contracts, the counterparty has the right, if exercised on December 23, 2020, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.

(5) For these contracts, the counterparty has the right, if exercised on December 31, 2021, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.

(6) Contracts entered subsequent to September 30, 2020.

Operating Netback

The following table summarizes our operating netback on a per boe basis for our Canadian and U.S. operations for the three and nine months ended September 30, 2020 and 2019.

	Three Months Ended September 30					
	2020			2019		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**49,164**	**28,650**	**77,814**	58,134	36,793	94,927
Operating netback:						
Total sales, net of blending and other expense	**$ 32.76**	**$ 35.55**	**$ 33.79**	$ 45.96	$ 48.99	$ 47.14
Less:						
Royalties	**(2.72)**	**(10.53)**	**(5.59)**	(4.90)	(14.42)	(8.59)
Operating expense	**(12.73)**	**(6.03)**	**(10.26)**	(13.78)	(6.99)	(11.15)
Transportation expense	**(1.41)**	**—**	**(0.89)**	(1.85)	—	(1.13)
Operating netback	**$ 15.90**	**$ 18.99**	**$ 17.05**	$ 25.43	$ 27.58	$ 26.27
Realized financial derivatives (loss) gain	**—**	**—**	**(1.36)**	—	—	2.39
Operating netback after financial derivatives	**$ 15.90**	**$ 18.99**	**$ 15.69**	$ 25.43	$ 27.58	$ 28.66

	Nine Months Ended September 30					
	2020			2019		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**49,704**	**33,203**	**82,907**	58,904	39,221	98,125
Operating netback:						
Total sales, net of blending and other expense	**$ 28.60**	**$ 34.61**	**$ 31.01**	$ 47.69	$ 50.67	$ 48.88
Less:						
Royalties	**(2.49)**	**(10.11)**	**(5.54)**	(5.12)	(15.00)	(9.07)
Operating expense	**(13.63)**	**(7.25)**	**(11.08)**	(13.79)	(7.14)	(11.13)
Transportation expense	**(1.60)**	**—**	**(0.96)**	(2.18)	—	(1.31)
Operating netback	**$ 10.88**	**$ 17.25**	**$ 13.43**	$ 26.60	$ 28.53	$ 27.37
Realized financial derivatives gain	**—**	**—**	**1.35**	—	—	1.97
Operating netback after financial derivatives	**$ 10.88**	**$ 17.25**	**$ 14.78**	$ 26.60	$ 28.53	$ 29.34

Our operating netback after financial derivatives was $15.69/boe for Q3/2020 and $14.78/boe for YTD 2020 compared to $28.66/boe for Q3/2019 and $29.34/boe for YTD 2019. Operating netback was lower in both periods of 2020 relative to the comparative periods of 2019 due to the decrease in benchmark pricing which resulted in lower per unit sales, net of royalties, in Canada and the U.S. Total operating and transportation expense of $11.15/boe in Q3/2020 and $12.04/boe in YTD 2020 reflects our production optimization and cost savings initiatives which resulted in lower costs relative to $12.28/boe in Q3/2019 and $12.44/boe in YTD 2019. Including realized gains and losses on financial derivatives our operating net back was $15.69/boe for Q3/2020 and $14.78/boe for YTD 2020 compared to $28.66/boe in Q3/2019 and $29.34/boe in YTD 2019.

General and Administrative Expense

General and administrative ("G&A") expense includes head office and corporate costs such as salaries and employee benefits, public company costs and administrative recoveries earned for operating exploration and development activities on behalf of our working interest partners. G&A expense fluctuates with head office staffing levels and the level of operated exploration and development activity during the period.

The following table summarizes our G&A expense for the three and nine months ended September 30, 2020 and 2019.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for per boe)	**2020**	2019	Change	**2020**	2019	Change
Gross general and administrative expense	**$ 7,790**	$ 11,633	$ (3,843)	**$ 27,153**	$ 39,907	$ (12,754)
Overhead recoveries	**(49)**	(1,699)	1,650	**(2,199)**	(4,331)	2,132
General and administrative expense	**$ 7,741**	$ 9,934	$ (2,193)	**$ 24,954**	$ 35,576	$ (10,622)
General and administrative expense per boe	**$ 1.08**	$ 1.14	$ (0.06)	**$ 1.10**	$ 1.33	$ (0.23)

G&A expense was $7.7 million ($1.08/boe) for Q3/2020 and $25.0 million ($1.10/boe) in YTD 2020 compared to $9.9 million ($1.14/boe) for Q3/2019 and $35.6 million ($1.33/boe) for YTD 2019.

G&A expense for Q3/2020 and YTD 2020 was lower relative to Q3/2019 and YTD 2019 due to reduced staffing levels combined with our cost savings initiatives that included salary reductions. G&A for Q3/2020 and YTD 2020 includes $1.5 million and $3.5 million respectively related to the CEWS program. Despite lower production, G&A per boe was lower in Q3/2020 and YTD 2020 relative to comparative periods of 2019 due to our cost savings initiatives and the benefit of the CEWS.

G&A expense of $25.0 million ($1.10/boe) in YTD 2020 is below our annual guidance of $38 million ($1.30/boe) as YTD 2020 production exceeded the high end of our guidance range, and we benefited from additional cost savings and the CEWS program extension. Our annual guidance of $38 million ($1.30/boe) reflects our cost savings initiatives and the announced changes to the CEWS program.

Financing and Interest Expense

Financing and interest expense includes interest on our credit facilities, long-term notes and lease obligations as well as non-cash financing costs and the accretion on our debt issue costs and asset retirement obligations. Financing and interest expense varies depending on debt levels outstanding during the period, the applicable borrowing rates, CAD/USD foreign exchange rates, along with the carrying amount of asset retirement obligations and the discount rates used to present value these obligations.

The following table summarizes our financing and interest expense for the three and nine months ended September 30, 2020 and 2019.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for per boe)	**2020**	2019	Change	**2020**	2019	Change
Interest on credit facilities	**$ 3,366**	$ 4,650	$ (1,284)	**$ 11,749**	$ 15,171	$ (3,422)
Interest on long-term notes	**21,943**	21,955	(12)	**69,231**	67,382	1,849
Interest on lease obligations	**109**	147	(38)	**$ 360**	$ 475	(115)
Cash interest	**$ 25,418**	$ 26,752	$ (1,334)	**$ 81,340**	$ 83,028	$ (1,688)
Accretion of debt issue costs	**756**	1,607	(851)	**5,863**	3,753	2,110
Accretion of asset retirement obligations	**1,788**	3,407	(1,619)	**6,897**	10,268	(3,371)
Early redemption expense	**—**	—	—	**3,312**	—	3,312
Financing and interest expense	**$ 27,962**	$ 31,766	$ (3,804)	**$ 97,412**	$ 97,049	$ 363
Cash interest per boe	**$ 3.55**	$ 3.06	$ 0.49	**$ 3.58**	$ 3.10	$ 0.48
Financing and interest expense per boe	**$ 3.91**	$ 3.64	$ 0.27	**$ 4.29**	$ 3.62	$ 0.67

Financing and interest expense was $28.0 million in Q3/2020 and $97.4 million in YTD 2020 compared to $31.8 million in Q3/2019 and $97.0 million in YTD 2019.

Cash interest of $25.4 million ($3.55/boe) in Q3/2020 and $81.3 million ($3.58/boe) in YTD 2020 is slightly lower than $26.8 million ($3.06/boe) in Q3/2019 and $83.0 million ($3.10/boe) in YTD 2019. Interest on our credit facilities was lower in both periods of 2020 primarily due to a lower weighted average borrowing rate on amounts outstanding relative to 2019. The weighted average interest rate on our credit facilities was 2.5% in YTD 2020 compared to 3.7% in YTD 2019. Interest on our long-term notes was higher in YTD 2020 due to a temporary increase in the principal amount outstanding between the issuance of the US$500 million principal amount of 8.75% senior unsecured notes on February 5, 2020 and the redemption of the US$400 principal amount of 5.125% senior unsecured notes on February 20, 2020 along with the redemption of the $300 million principal amount of 6.625% senior unsecured notes on March 5, 2020.

Financing and interest expense for YTD 2020 includes the accelerated amortization of debt issue costs and $3.3 million of early redemption expense associated with the $300 million principal amount of 6.625% senior unsecured notes which were redeemed at 101.104% of the principal amount on March 5, 2020.

Cash interest expense of $3.58/boe is slightly below our annual guidance of $3.70/boe as production in YTD 2020 exceeded our annual guidance. We expect cash financing and interest expense of $108.0 million ($3.70/boe) for 2020.

Exploration and Evaluation Expense

Exploration and evaluation ("E&E") expense is related to the expiry of leases and the de-recognition of costs for exploration programs that have not demonstrated commercial viability and technical feasibility. E&E expense will vary depending on the timing of expiring leases, the accumulated costs of the expiring leases and the economic facts and circumstances related to the Company's exploration programs. Exploration and evaluation expense was $8.9 million for Q3/2020 and $11.0 million in YTD 2020 which is higher than $2.1 million for Q3/2019 and $8.7 million in YTD 2019 due to a higher amount of acreage expiring in 2020 relative to 2019.

Depletion and Depreciation

Depletion and depreciation expense varies with the carrying amount of the Company's oil and gas properties, the amount of proved plus probable reserves volumes and the rate of production for the period. The following table summarizes depletion and depreciation expense for the three and nine months ended September 30, 2020 and 2019.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for per boe)	**2020**	2019	Change	**2020**	2019	Change
Depletion	**$ 104,547**	$ 178,364	$ (73,817)	**$ 386,587**	$ 547,345	$ (160,758)
Depreciation	**1,907**	2,058	(151)	**5,793**	4,203	1,590
Depletion and depreciation	**$ 106,454**	$ 180,422	$ (73,968)	**$ 392,380**	$ 551,548	$ (159,168)
Depletion and depreciation per boe	**$ 14.87**	$ 20.66	$ (5.79)	**$ 17.27**	$ 20.59	$ (3.32)

Depletion and depreciation expense was $106.5 million ($14.87/boe) for Q3/2020 and $392.4 million ($17.27/boe) in YTD 2020 compared to $180.4 million ($20.66/boe) for Q3/2019 and $551.5 million ($20.59/boe) for YTD 2019. Total depletion and depreciation expense and the depletion rate per boe were lower in both periods of 2020 relative to the comparative periods of 2019 due to lower production in 2020 along with $2.6 billion of impairment write-downs recorded in Q1/2020 which reduced the depletable base of our oil and gas properties.

Impairment

We did not identify indicators of impairment or impairment reversal for any of our cash generating units ("CGU") at September 30, 2020.

At March 31, 2020, we identified indicators of impairment due to the sharp decline in forecasted commodity prices. We performed impairment tests on the E&E assets and oil and gas properties for our six CGUs. We recorded total impairments of $2.7 billion in Q1/2020 as the carrying value of the E&E assets and oil and gas properties of our CGUs exceeded their estimated recoverable amounts. The total impairment includes $2.6 billion related to the CGUs comprising oil and gas properties and $0.1 billion related to the CGUs comprising E&E assets.

The recoverable amount of each CGU was calculated at March 31, 2020 using the following benchmark reference prices for the years 2020 to 2029 adjusted for commodity differentials specific to the Company.

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
WTI crude oil (US$/bbl)	29.17	40.45	49.17	53.28	55.66	56.87	58.01	59.17	60.35	61.56
WCS heavy oil (CA$/bbl)	19.21	34.65	46.34	51.25	54.28	55.72	56.96	58.22	59.51	60.82
LLS crude oil (US$/bbl)	32.17	43.80	52.55	56.68	59.10	60.35	61.52	62.72	63.94	65.19
Edmonton par oil (CA$/bbl)	29.22	46.85	59.27	65.02	68.43	69.81	71.24	72.70	74.19	75.71
Henry Hub gas (US$/mmbtu)	2.10	2.58	2.79	2.86	2.93	3.00	3.07	3.13	3.19	3.25
AECO gas (CA$/mmbtu)	1.74	2.20	2.38	2.45	2.53	2.60	2.66	2.72	2.79	2.85
Exchange rate (CAD/USD)	1.41	1.37	1.34	1.34	1.34	1.33	1.33	1.33	1.33	1.33

This data is combined with assumptions relating to long-term prices, inflation rates and exchange rates together with estimates of transportation costs and pricing of competing fuels to forecast long-term energy prices, consistent with external sources of information. The prices and costs subsequent to 2029 have been adjusted for inflation at an annual rate of 2.0%.

The following table summarizes the recoverable amount and impairment at March 31, 2020 and demonstrates the sensitivity of the estimated recoverable amount of the Company's CGUs comprising oil and gas properties to reasonably possible changes in key assumptions inherent in the estimate.

	Recoverable amount	Impairment	Change in discount rate of 1%	Change in oil price of $2.50/bbl	Change in gas price of $0.25/mcf
Conventional CGU	$ 37,444	$ 41,000	$ 3,000	$ 3,500	$ 8,500
Peace River CGU	109,631	345,000	9,500	53,500	3,000
Lloydminster CGU	227,967	470,000	25,000	69,500	—
Duvernay CGU	61,197	5,000	5,500	9,500	1,500
Viking CGU	962,134	915,000	57,000	123,000	4,000
Eagle Ford CGU	1,576,423	812,488	120,750	141,500	32,000
	$ 2,974,796	$ 2,588,488	$ 220,750	$ 400,500	$ 49,000

Share-Based Compensation Expense

Share-based compensation ("SBC") expense includes expense associated with our Share Award Incentive Plan and our Incentive Award Plan. SBC expense associated with our Share Award Incentive Plan is recognized in net income or loss over the vesting period of the awards with a corresponding increase in contributed surplus. SBC expense associated with our Incentive Award Plan is recognized in net income or loss over the vesting period of the awards with a corresponding financial liability and includes gains or losses on equity total return swaps used to fix the aggregate cost of new grants made under the plan. SBC expense varies with the quantity of unvested share awards outstanding and the grant date fair value assigned to the share awards.

We recorded SBC expense of $2.9 million for Q3/2020 and $8.7 million for YTD 2020 compared to $3.4 million for Q3/2019 and $14.2 million for YTD 2019. SBC expense is lower in both periods of 2020 as the total value of awards granted in 2020 was lower than prior years. The total expense for YTD 2020 is comprised of non-cash compensation expense of $7.0 million related to the Share Award Incentive Plan and cash compensation expense of $1.7 million related to the Incentive Award Plan.

Foreign Exchange

Unrealized foreign exchange gains and losses represent the change in value of the long-term notes and credit facilities denominated in U.S. dollars. The long-term notes and credit facilities are translated to Canadian dollars on the balance sheet date using the closing CAD/USD exchange rate. When the Canadian dollar strengthens against the U.S. dollar at the end of the current period compared to the previous period an unrealized gain is recorded and conversely when the Canadian dollar weakens at the end of the current period compared to the previous period an unrealized loss is recorded. Realized foreign exchange gains and losses are due to day-to-day U.S. dollar denominated transactions occurring in our Canadian functional currency entities.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for exchange rates)	**2020**	2019	Change	**2020**	2019	Change
Unrealized foreign exchange (gain) loss	**$ (25,880)**	$ 13,855	$ (39,735)	**$ 28,125**	$ (38,404)	$ 66,529
Realized foreign exchange (gain) loss	**(351)**	382	(733)	**(437)**	426	(863)
Foreign exchange (gain) loss	**$ (26,231)**	$ 14,237	$ (40,468)	**$ 27,688**	$ (37,978)	$ 65,666
CAD/USD exchange rates:						
At beginning of period	**1.3616**	1.3091		**1.2965**	1.3646	
At end of period	**1.3324**	1.3244		**1.3324**	1.3244	

We recorded unrealized foreign exchange gains of $25.9 million for Q3/2020 due to the strengthening of the Canadian dollar relative to the U.S. dollar at September 30, 2020 compared to June 30, 2020. This compares to an unrealized foreign exchange loss of $13.9 million for Q3/2019 due to the weakening of the Canadian dollar relative to the U.S. dollar at September 30, 2019 relative to June 30, 2019.

We recorded an unrealized foreign exchange loss of $28.1 million for YTD 2020 due to the weakening of the Canadian dollar relative to the U.S. dollar at September 30, 2020 compared to December 31, 2019. This compares to an unrealized foreign exchange gain of $38.4 million in YTD 2019 due to the strengthening of the Canadian dollar relative to the U.S. dollar at September 30, 2019 relative to December 31, 2018.

Realized foreign exchange gains and losses will fluctuate depending on the amount and timing of day-to-day U.S. dollar denominated transactions for our Canadian operations. We recorded a realized foreign exchange gain of $0.4 million for Q3/2020 and YTD 2020 compared to a loss of $0.4 million for Q3/2019 and YTD 2019.

Income Taxes

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2020**	2019	Change	**2020**	2019	Change
Current income tax expense	**$ 322**	$ 501	$ (179)	**$ 880**	$ 1,591	$ (711)
Deferred income tax expense (recovery)	**696**	1,082	(386)	**(261,481)**	(14,958)	(246,523)
Total income tax expense (recovery)	**$ 1,018**	$ 1,583	$ (565)	**$ (260,601)**	$ (13,367)	$ (247,234)

Current income tax expense was $0.3 million for Q3/2020 and $0.9 million for YTD 2020 compared to $0.5 million for Q3/2019 and $1.6 million in YTD 2019. Current income tax was lower in both periods of 2020 due to lower state tax owed on our U.S. operations relative to the comparative periods of 2019.

We recorded a deferred tax recovery of $261.5 million for YTD 2020 which was lower compared to a $15.0 million recovery for YTD 2019 as income before tax was lower due to the impairment recorded in Q1/2020. We recorded a deferred income tax expense of $0.7 million for Q3/2020 compared to $1.1 million for Q3/2019. Deferred income tax expense for Q3/2020 did not decrease in proportion to the decrease in net income relative to Q3/2019 as deferred income tax in our Canadian operations is offset by a change in the valuation allowance recorded against the deferred income tax asset in Canada.

As disclosed in the 2019 annual financial statements, certain indirect subsidiaries received reassessments from the Canada Revenue Agency (the "CRA”) that deny $591 million of non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. In September 2016, we filed notices of objection with the CRA appealing each reassessment received. There has been no change in the status of these reassessments since an Appeals Officer was assigned to our file in July 2018. We remain confident that our original tax filings are correct and intend to defend these tax filings through the appeals process.

Net Income (Loss) and Adjusted Funds Flow

The components of adjusted funds flow and net income or loss for the three and nine months ended September 30, 2020 and 2019 are set forth in the following table.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2020**	2019	Change	**2020**	2019	Change
Petroleum and natural gas sales	**$ 252,538**	$ 424,600	$ (172,062)	**$ 741,841**	$ 1,360,024	$ (618,183)
Royalties	**(40,052)**	(75,017)	34,965	**(125,928)**	(242,959)	117,031
Revenue, net of royalties	**212,486**	349,583	(137,097)	**615,913**	1,117,065	(501,152)
Expenses						
Operating	**(73,447)**	(97,377)	23,930	**(251,597)**	(298,143)	46,546
Transportation	**(6,372)**	(9,903)	3,531	**(21,745)**	(35,102)	13,357
Blending and other	**(10,673)**	(12,950)	2,277	**(37,490)**	(50,628)	13,138
Operating netback	**$ 121,994**	$ 229,353	$ (107,359)	**$ 305,081**	$ 733,192	$ (428,111)
General and administrative	**(7,741)**	(9,934)	2,193	**(24,954)**	(35,576)	10,622
Cash financing and interest	**(25,418)**	(26,752)	1,334	**(81,340)**	(83,028)	1,688
Realized financial derivatives (loss) gain	**(9,743)**	20,857	(30,600)	**30,731**	52,664	(21,933)
Realized foreign exchange gain (loss)	**351**	(382)	733	**437**	(426)	863
Other income	**—**	738	(738)	**2,007**	5,044	(3,037)
Current income tax expense	**(322)**	(501)	179	**(880)**	(1,591)	711
Share-based compensation	**(613)**	—	(613)	**(1,752)**	—	(1,752)
Adjusted funds flow	**$ 78,508**	$ 213,379	$ (134,871)	**$ 229,330**	$ 670,279	$ (440,949)
Exploration and evaluation	**(8,909)**	(2,138)	(6,771)	**(11,000)**	(8,667)	(2,333)
Depletion and depreciation	**(106,454)**	(180,422)	73,968	**(392,380)**	(551,548)	159,168
Non-cash share-based compensation	**(2,336)**	(3,401)	1,065	**(6,973)**	(14,245)	7,272
Non-cash financing and accretion	**(2,544)**	(5,014)	2,470	**(16,072)**	(14,021)	(2,051)
Non-cash other income	**293**	—	293	**293**	—	293
Unrealized financial derivatives (loss) gain	**(7,284)**	7,666	(14,950)	**19,425**	(30,922)	50,347
Unrealized foreign exchange gain (loss)	**25,880**	(13,855)	39,735	**(28,125)**	38,404	(66,529)
Gain on dispositions	**98**	18	80	**246**	1,075	(829)
Impairment	**—**	—	—	**(2,716,349)**	—	(2,716,349)
Deferred income tax (expense) recovery	**(696)**	(1,082)	386	**261,481**	14,958	246,523
Net income (loss) for the period	**$ (23,444)**	$ 15,151	$ (38,595)	**$(2,660,124)**	$ 105,313	$(2,765,437)

We generated adjusted funds flow of $78.5 million for Q3/2020 and $229.3 million for YTD 2020 compared to $213.4 million reported in Q3/2019 and $670.3 million for YTD 2019. The decrease in adjusted funds flow in both periods of 2020 is primarily due to the decline in commodity benchmark prices which resulted in a $133.1 million decrease in revenue, net of royalties and blending and other expense for Q3/2020 and a $486.3 million decrease for YTD 2020. This decrease in adjusted funds flow in 2020 relative to 2019 was mitigated by our costs savings initiatives which resulted in a $29.7 million reduction in operating, transportation, and general and administrative expenses for Q3/2020 and $70.5 million for YTD 2020.

We reported a net loss of $23.4 million for Q3/2020 and $2.7 billion for YTD 2020 compared to net income of $15.2 million and $105.3 million for Q2/2019 and YTD 2019 respectively. The net loss for Q3/2020 was primarily a result of lower commodity prices and shut-in production which resulted in a $134.9 million decrease in adjusted funds flow compared to Q3/2019. This decrease was partially offset by lower depletion and unrealized gains and losses on derivatives and foreign exchange in Q3/2020 relative to Q3/2019 which resulted in the $38.6 million decrease in net income over the same period. We recorded total impairments of $2.7 billion during YTD 2020 which was the main reason for the net loss of $2.7 billion recorded for the period.

Other Comprehensive Income (Loss)

Other comprehensive income or loss is comprised of the foreign currency translation adjustment on U.S. net assets which is not recognized in profit or loss. The foreign currency translation loss of $30.3 million for Q3/2020 and the gain of $90.2 million for YTD 2020 relates to the change in value of our U.S. net assets expressed in Canadian dollars and is due to the change of the Canadian dollar relative to the U.S. dollar at September 30, 2020 compared to June 30, 2020 and December 31, 2019. The CAD/USD exchange rate was 1.3324 CAD/USD as at September 30, 2020 compared to 1.3616 CAD/USD at March 31, 2020 and 1.2965 CAD/USD at December 31, 2019.

Capital Expenditures

Capital expenditures for the three and nine months ended September 30, 2020 and 2019 are summarized as follows.

	Three Months Ended September 30					
	2020			2019		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ —**	**$ 12,020**	**$ 12,020**	$ 85,633	$ 38,731	$ 124,364
Facilities	**2,056**	**—**	**2,056**	9,934	2,991	12,925
Land, seismic and other	**1,826**	**—**	**1,826**	1,207	589	1,796
Total exploration and development	**$ 3,882**	**$ 12,020**	**$ 15,902**	$ 96,774	$ 42,311	$ 139,085
Total acquisitions, net of proceeds from divestitures	**$ (98)**	**$ —**	**$ (98)**	$ (30)	$ —	$ (30)

	Nine Months Ended September 30					
	2020			2019		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 99,545**	**$ 71,859**	**$ 171,404**	$ 228,570	$ 120,716	$ 349,286
Facilities	**23,753**	**299**	**24,052**	31,401	7,573	38,974
Land, seismic and other	**6,624**	**451**	**7,075**	9,932	982	10,914
Total exploration and development	**$ 129,922**	**$ 72,609**	**$ 202,531**	$ 269,903	$ 129,271	$ 399,174
Total acquisitions, net of proceeds from divestitures	**$ (149)**	**$ —**	**$ (149)**	$ 1,617	$ —	$ 1,617

Exploration and development expenditures were $15.9 million for Q3/2020 and $202.5 million for YTD 2020 compared to $139.1 million for Q3/2019 and $399.2 million for YTD 2019. Expenditures in Q3/2020 and YTD 2020 were lower than the comparative periods of 2019 as we suspended our operated capital activity in Canada and moderated the pace of development in the U.S. in response to the significant decline in crude oil prices in March 2020.

In Canada, we invested $3.9 million on exploration and development activities in Q3/2020 which is $92.9 million lower than $96.8 million in Q3/2019. Development expenditures of $3.9 million for Q3/2020 relate to $2.1 million of well-site equipping costs associated with Q4/2020 completion activity along with land acquisition costs of $1.8 million. Drilling and completion operations were suspended after the sharp decline in crude oil prices in March 2020 and we did not drill any wells in our Canadian operations during Q3/2020. Exploration and development expenditures of $129.9 million for YTD 2020 included costs associated with drilling 72 (69.2 net) light oil wells in the Viking, 2 (2.0 net) light oil wells in the Duvernay, 33 (33.0 net) heavy oil wells, 6 (6.0 net) stratigraphic exploration wells and investing $23.8 million on facilities. Exploration and development expenditures of $269.9 million for YTD 2019 included costs associated with 223 (193.7 net) light oil wells, 25 (25.0 net) heavy oil wells and 4 (4.0 net) stratigraphic exploration wells. Total exploration and development costs were lower in YTD 2020 relative to YTD 2019 as we suspended development operations following the sharp decline in crude oil pricing in March 2020.

Total U.S. exploration and development expenditures were $12.0 million for Q3/2020 which is $30.3 million lower than $42.3 million for Q3/2019. Exploration and development expenditures of $12.0 million included costs associated with drilling 22 (5.4 net) wells along with 6 (0.8 net) wells that were brought on production during Q3/2020. Exploration and development expenditures of $72.6 million for YTD 2020 included costs associated with the drilling of 39 (9.2 net) wells and completion activities on 53 (11.5 net) wells. Development expenditures were lower in YTD 2020 which was primarily due to lower drilling and completions activity relative to YTD 2019 when we drilled 65 (14.5 net) wells and brought 85 (18.5 net) wells on production and spent $129.3 million.

Our 2020 annual guidance range of $260 - $290 million reflects a more active development program in Q4/2020 in Canada and the U.S. in anticipation of an improved price environment leading into 2021.

CAPITAL RESOURCES AND LIQUIDITY

We took action to improve our capital structure and financial liquidity during YTD 2020. On February 5, 2020, we issued US$500 million of senior unsecured notes bearing interest at 8.75% which mature on April 1, 2027. Proceeds from the issuance were used in conjunction with availability on our credit facilities to complete the early redemption of the US$400 million principal amount of 5.125% senior unsecured notes due June 1, 2021 and the $300 million principal amount of 6.625% senior unsecured notes due July 19, 2022. We also negotiated an extension to the maturity of our credit facilities from April 2, 2021 to April 2, 2024. As a result of these actions we do not have any debt maturities until 2024 and we had $425.8 million of undrawn capacity on our credit facilities at September 30, 2020.

Our objective for capital management involves maintaining a flexible capital structure and sufficient sources of liquidity to execute our capital programs, while meeting our short and long-term commitments. We strive to actively manage our capital structure in response to changes in economic conditions. At September 30, 2020, our capital structure was comprised of shareholders' capital, long-term notes, trade and other receivable, trade and other payables and the credit facilities.

During 2020 we took additional action to protect our financial liquidity in response to lower oil prices and the global economic instability related to COVID-19. Our 2020 exploration and development expenditures were reduced by moderating the pace of activity in the U.S. and suspending drilling and completion operations in Canada. Certain high cost, low margin, production was shut-in for a portion of 2020 when netbacks were challenged by low commodity prices. We remain committed to our cost savings initiatives which resulted in lower operating expenses and general administrative costs during YTD 2020. We have also taken advantage of all government assistance programs available to our industry. These actions resulted in free cash flow of $59.9 million for Q3/2020 and $16.3 million for YTD 2020.

The capital intensive nature of our operations requires us to maintain adequate sources of liquidity to fund ongoing exploration and development. Our capital resources consist primarily of adjusted funds flow, available credit facilities and proceeds received from the divestiture of oil and gas properties. We believe that our internally generated adjusted funds flow and our existing undrawn credit facilities will provide sufficient liquidity to fund our planned capital expenditures. Adjusted funds flow depends on a number of factors, including commodity prices, production and sales volumes, royalties, operating expenses, taxes and foreign exchange rates. In order to manage our capital structure and liquidity, we may from time to time issue equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

At September 30, 2020, net debt of $1.91 billion was $34.3 million higher than $1.87 billion at December 31, 2019. Free cash flow of $16.3 million generated during YTD 2020 was directed towards debt repayment and reduced net debt at September 30, 2020. Net debt increased due to a $30.9 million increase in the reported amount of our U.S. dollar denominated net debt at September 30, 2020 due to a weaker Canadian dollar. We also incurred total transaction and financing costs of $17.6 million related to the refinancing transactions in Q1/2020 including the issuance of the US$500 million senior notes due 2027, the early redemption of the US$400 million senior notes due 2021 and the $300 million senior notes due 2022 along with extending the maturity of our credit facilities to 2024.

We monitor our capital structure and liquidity requirements using a net debt to adjusted funds flow ratio calculated on a twelve month trailing basis. At September 30, 2020, our net debt to adjusted funds flow ratio was 4.1 compared to a ratio of 2.1 as at December 31, 2019. The increase in the net debt to adjusted funds flow ratio relative to December 31, 2019 is attributed to lower adjusted funds flow due to lower commodity pricing.

Credit Facilities

At September 30, 2020, the principal amount of credit facilities and letters of credit outstanding was $640.3 million and we had $425.8 million of undrawn capacity under our credit facilities that total approximately $1.07 billion. Our credit facilities include US$575 million of revolving credit facilities and a $300 million non-revolving term loan (collectively, the "Credit Facilities").

On March 3, 2020, we amended our Credit Facilities to extend maturity from April 2, 2021 to April 2, 2024. These facilities will automatically be extended to June 4, 2024 providing we have either refinanced, or have the ability to repay, the outstanding 2024 long-term notes with existing credit capacity as of April 1, 2024.

The Credit Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The Credit Facilities contain standard commercial covenants in addition to the financial covenants detailed below. There are no mandatory principal payments required prior to maturity which could be extended upon our request. Advances (including letters of credit) under the Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank’s prime lending rate, bankers’ acceptance discount rates or London Interbank Offered Rates, plus applicable margins. In the event that Baytex breaches any of the covenants under the Credit Facilities, Baytex may be required to repay, refinance or renegotiate the loan terms and may be restricted from taking on further debt or paying dividends to shareholders.

The agreements and associated amending agreements relating to the Credit Facilities are accessible on the SEDAR website at www.sedar.com.

The weighted average interest rate on the Credit Facilities was 1.9% for Q3/2020 and 2.5% for YTD 2020 compared to 3.6% for Q3/2019 and 3.7% for YTD 2019.

Financial Covenants

At September 30, 2020, we were in compliance with all of the covenants contained in our Credit Facilities and we expect to remain in compliance with the financial covenants applicable to our credit facilities at current forward commodity prices. A decrease or a sustained period of low commodity prices may result in non-compliance with our financial covenants and reduced liquidity on our existing credit facilities. Non-compliance with the financial covenants in our credit facilities could result in our debt becoming due and payable on demand.

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at September 30, 2020.

Covenant Description	Position as at September 30, 2020	Covenant
Senior Secured Debt(1) to Bank EBITDA(2) (Maximum Ratio)	**1.1:1.0**	3.5:1.0
Interest Coverage(3) (Minimum Ratio)	**5.4:1.0**	2.0:1.0

(1) "Senior Secured Debt" is defined as the principal amount of the credit facilities and other secured obligations identified in the credit agreement. As at September 30, 2020, the Company's Senior Secured Debt totaled $640.3 million which includes $624.8 million of principal amounts outstanding and $15.5 million of letters of credit.

(2) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expenses, income tax, non-recurring losses, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration and evaluation expenses, impairment, deferred income tax expense and recovery, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation) and is calculated based on a trailing twelve month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the twelve months ended September 30, 2020 was $566.1 million.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding accretion of debt issue costs and asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expenses, excluding accretion of debt issue costs and asset retirement obligations, for the three months ended September 30, 2020 were $105.2 million.

Long-Term Notes

We have two series of long-term notes outstanding that total $1.2 billion as at September 30, 2020. The long-term notes do not contain any financial maintenance covenants. The long-term notes contain a debt incurrence covenant that restricts our ability to raise additional debt beyond our existing Credit Facilities and long-term notes unless we maintain a minimum fixed charge coverage ratio (computed as the ratio of Bank EBITDA to financing and interest expenses on a trailing twelve month basis) of 2.00:1.00. The fixed charge coverage ratio was 5.0:1.0 as at September 30, 2020.

On June 6, 2014, we issued US$800 million of senior unsecured notes, comprised of US$400 million of 5.125% notes due June 1, 2021 (the "5.125% Notes"), which were redeemed February 20, 2020, and US$400 million of 5.625% notes due June 1, 2024 (the "5.625% Notes"), which remain outstanding. The 5.625% Notes pay interest semi-annually with the principal amount repayable at maturity. As of June 1, 2019, the 5.625% Notes are redeemable at our option, in whole or in part, at specified redemption prices and will be redeemable at par from June 1, 2022 to maturity.

On February 5, 2020, we issued US$500 million aggregate principal amount of senior unsecured notes due April 1, 2027 bearing interest at a rate of 8.75% per annum payable semi-annually (the "8.75% Senior Notes)". The 8.75% Senior Notes are redeemable at our option, in whole or in part, at specified redemption prices after April 1, 2023 and will be redeemable at par from April 1, 2026 to maturity. Transaction costs of $12.5 million were incurred in conjunction with the issuance which resulted in net proceeds of $652.2 million.

On February 20, 2020, we used a portion of the net proceeds from the issuance of the 8.75% Senior Notes to complete the early redemption of the US$400 million principal amount of the 5.125% senior unsecured notes due June 1, 2021 at par plus accrued interest. The payment at redemption was $530.4 million.

On March 5, 2020, we completed the early redemption of the $300 million principal amount of the 6.625% senior unsecured notes due July 19, 2022 at 101.104% of the principal amount plus accrued interest. The payment at redemption includes principal of $300.0 million plus early redemption expense of $3.3 million.

Shareholders' Capital

We are authorized to issue an unlimited number of common shares and 10.0 million preferred shares. The rights and terms of preferred shares are determined upon issuance. During the nine months ended September 30, 2020, we issued 2.9 million common shares pursuant to our share-based compensation program. As at November 2, 2020, we had 561.2 million common shares issued and outstanding and no preferred shares issued and outstanding.

Contractual Obligations

We have a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact our adjusted funds flow in an ongoing manner. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of September 30, 2020 and the expected timing for funding these obligations are noted in the table below.

($ thousands)	**Total**	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	**$ 179,482**	$ 179,482	$ —	$ —	$ —
Credit facilities[1] [2]	**624,826**	—	—	624,826	—
Long-term notes[2]	**1,199,160**	—	—	532,960	666,200
Interest on long-term notes[3]	**489,037**	88,272	176,543	136,544	87,678
Lease agreements	**11,132**	6,086	4,449	597	—
Processing agreements	**8,912**	3,403	1,396	503	3,610
Transportation agreements	**102,101**	13,619	41,372	28,345	18,765
Total	**$ 2,614,650**	$ 290,862	$ 223,760	$ 1,323,775	$ 776,253

(1) The credit facilities matures on April 2, 2024. Maturity will automatically be extended to June 4, 2024 providing Baytex has either refinanced, or has the ability to repay, the outstanding 2024 long-term notes with existing credit capacity as of April 1, 2024.

(2) Principal amount of instruments.

(3) Excludes interest on our credit facilities as interest payments fluctuate based on a floating rate of interest and changes in the outstanding balances.

We also have ongoing obligations related to the abandonment and reclamation of well sites and facilities when they reach the end of their economic lives. Programs to abandon and reclaim well sites and facilities are undertaken regularly in accordance with applicable legislative requirements.

QUARTERLY FINANCIAL INFORMATION

	2020			2019				2018
($ thousands, except per common share amounts)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Petroleum and natural gas sales	**252,538**	152,689	336,614	445,895	424,600	482,000	453,424	358,437
Net income (loss)	**(23,444)**	(138,463)	(2,498,217)	(117,772)	15,151	78,826	11,336	(231,238)
Per common share - basic	**(0.04)**	(0.25)	(4.46)	(0.21)	0.03	0.14	0.02	(0.42)
Per common share - diluted	**(0.04)**	(0.25)	(4.46)	(0.21)	0.03	0.14	0.02	(0.42)
Adjusted funds flow	**78,508**	17,887	132,935	232,147	213,379	236,130	220,770	110,828
Per common share - basic	**0.14**	0.03	0.24	0.42	0.38	0.42	0.40	0.20
Per common share - diluted	**0.14**	0.03	0.24	0.42	0.38	0.42	0.40	0.20
Exploration and development	**15,902**	9,852	176,777	153,117	139,085	106,246	153,843	184,162
Canada	**3,882**	2,929	123,110	104,460	96,774	68,259	104,870	125,507
U.S.	**12,020**	6,923	53,667	48,657	42,311	37,987	48,973	58,655
Acquisitions, net of divestitures	**(98)**	(11)	(40)	563	(30)	1,647	—	229
Net debt	**1,906,079**	1,994,953	2,051,617	1,871,791	1,971,339	2,028,686	2,175,241	2,265,167
Total assets	**3,156,414**	3,267,820	3,441,040	5,914,083	6,233,875	6,222,190	6,359,157	6,377,198
Common shares outstanding	**561,163**	560,545	560,483	558,305	557,972	556,798	555,872	554,060
Daily production								
Total production (boe/d)	**77,814**	72,508	98,452	96,360	94,927	98,402	101,115	98,890
Canada (boe/d)	**49,164**	37,691	62,262	57,794	58,134	58,580	60,018	60,453
U.S. (boe/d)	**28,650**	34,817	36,190	38,566	36,793	39,822	41,097	38,437
Benchmark prices								
WTI oil (US$/bbl)	**40.93**	27.85	46.17	56.96	56.45	59.81	54.90	58.81
WCS heavy (US$/bbl)	**31.84**	16.38	25.65	41.13	44.21	49.14	42.61	19.39
CAD/USD avg exchange rate	**1.3316**	1.3860	1.3445	1.3201	1.3207	1.3376	1.3293	1.3215
AECO gas ($/mcf)	**2.18**	1.91	2.14	2.34	1.04	1.17	1.94	1.94
NYMEX gas (US$/mmbtu)	**1.98**	1.72	1.95	2.50	2.23	2.64	3.15	3.64
Sales price ($/boe)	**33.79**	22.31	35.19	48.25	47.14	51.49	47.98	37.89
Royalties ($/boe)	**(5.59)**	(4.42)	(6.33)	(8.72)	(8.59)	(9.67)	(8.94)	(8.77)
Operating expense ($/boe)	**(10.26)**	(11.17)	(11.66)	(11.23)	(11.15)	(11.22)	(11.02)	(10.76)
Transportation expense ($/boe)	**(0.89)**	(0.76)	(1.15)	(1.00)	(1.13)	(1.33)	(1.46)	(1.21)
Operating netback ($/boe)	**17.05**	5.96	16.05	27.30	26.27	29.27	26.56	17.15
Financial derivatives gain (loss) ($/boe)	**(1.36)**	2.06	3.00	2.59	2.39	1.45	2.07	(0.34)
Operating netback after financial derivatives ($/boe)	**15.69**	8.02	19.05	29.89	28.66	30.72	28.63	16.81

Our results for the previous eight quarters reflect the disciplined execution of our development programs and management of production in response to fluctuations in the prices for the commodities we produce. Production reached a high of 101,115 boe/d during Q1/2019 after relatively stable crude oil prices supported an active development program in Canada and the U.S. leading into 2019. Production was relatively consistent in the quarters following Q1/2019 until we shut-in production in Canada and moderated the pace of activity in the U.S. after the sharp decline in crude oil prices in March 2020. Production of 77,814 boe/d for Q3/2020 reflects reduced capital spending in response to low commodity prices for the second consecutive quarter.

North American benchmark commodity prices were stable throughout 2019 and were relatively strong leading into Q1/2020 with the West Texas Intermediate ("WTI") benchmark price averaging US$57.53/bbl in January. Decisions made by Saudi Arabia and Russia to increase production of crude oil as demand was decreasing due to the spread of COVID-19 resulted in a sharp decline in global crude oil prices with WTI averaging US$27.85/bbl in Q2/2020. Prices improved and were relatively stable during Q3/2020 as OPEC+ agreed to reinstate production curtailments and measures to control the spread of COVID-19 were relaxed. Despite this recent improvement commodity prices remained low with WTI averaging US$40.93/bbl for Q3/2020. The impact of low commodity prices is reflected in our realized sales price of $33.79/boe for Q3/2020. Our development programs were significantly reduced in Canada and the U.S. as a result of this decline in crude oil pricing with exploration and development spending of $15.9 million during Q3/2020.

Adjusted funds flow is directly impacted by our average daily production and changes in benchmark commodity prices which are the basis for our realized sales price. Adjusted funds flow improved throughout 2019 due to increased production and strong well performance along with higher realizations associated with the higher weighting of light oil production. Adjusted funds flow of $78.5 million in Q3/2020 reflects the impact of lower commodity prices and reduced development expenditures.

Net debt can fluctuate on a quarterly basis depending on the timing of exploration and development expenditures, changes in our adjusted funds flow and the closing CAD/USD exchange rate which is used to translate our U.S. dollar denominated debt. Net debt has decreased from $2.3 billion at Q4/2018 to $1.9 billion at Q3/2020 which is primarily due to adjusted funds flow exceeding exploration and development expenditures by $303.6 million over the last eight quarters which reflects our efforts to preserve liquidity during periods of challenging crude oil prices. Our net debt has also be reduced by a decrease in the CAD/USD exchange rate used to translate our U.S. dollar denominated debt from 1.3646 CAD/USD at Q4/2018 to 1.3324 CAD/USD at Q3/2020.

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at September 30, 2020, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

There have been no changes in our critical accounting estimates in the nine months ended September 30, 2020. Further information on our critical accounting policies and estimates can be found in the notes to the audited annual consolidated financial statements and MD&A for the year ended December 31, 2019.

NYSE LISTING

On March 24, 2020 we received notice from the New York Stock Exchange (“NYSE”) that Baytex was no longer in compliance with one of the NYSE’s continued listing standards because the average closing price of Baytex’s common shares was less than US$1.00 per share over a consecutive 30 trading period. At this time, Baytex has not regained compliance and expects that its common shares will be delisted from the NYSE on December 3, 2020.

NON-GAAP AND CAPITAL MEASUREMENT MEASURES

In this MD&A, we refer to certain capital management measures (such as adjusted funds flow, exploration and development expenditures, free cash flow, net debt, operating netback and Bank EBITDA) which do not have any standardized meaning prescribed by Canadian Generally Accepted Accounting Principles ("GAAP"). While adjusted funds flow, exploration and development expenditures, free cash flow, net debt, operating netback and Bank EBITDA are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures presented by other reporting issuers. We believe that inclusion of these non-GAAP financial measures provide useful information to investors and shareholders when evaluating the financial results of the Company.

Adjusted Funds Flow

We consider adjusted funds flow a key measure that provides a more complete understanding of operating performance and our ability to generate funds for exploration and development expenditures, debt repayment, settlement of our abandonment obligations and potential future dividends. In addition, we use a ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. Changes in non-cash working capital are eliminated in the determination of adjusted funds flow as the timing of collection, payment and incurrence is variable and by excluding them from the calculation we are able to provide a more meaningful measure of our operations on a continuing basis.

Adjusted funds flow should not be construed as an alternative to performance measures determined in accordance with GAAP, such as cash flow from operating activities and net income or loss.

The following table reconciles cash flow from operating activities to adjusted funds flow.

	Three Months Ended September 30		Nine Months Ended September 30	
($ thousands)	**2020**	2019	**2020**	2019
Cash flow from operating activities	**$ 93,688**	$ 194,970	**$ 302,079**	$ 599,920
Change in non-cash working capital	**(16,391)**	17,275	**(78,829)**	59,499
Asset retirement obligations settled	**1,211**	1,134	**6,080**	10,860
Adjusted funds flow	**$ 78,508**	$ 213,379	**$ 229,330**	$ 670,279

Exploration and Development Expenditures

We use exploration and development expenditures to measure and evaluate the performance of our capital programs. The total amount of exploration and development expenditures is managed as part of our budgeting process and can vary from period to period depending on the availability of adjusted funds flow and other sources of liquidity. We eliminate changes in non-cash working capital, acquisition and dispositions, and additions to other plant and equipment from investing activities as these amounts are generated by activities outside of our programs to explore and develop our existing properties.

Changes in non-cash working capital are eliminated in the determination of exploration and development expenditures as the timing of collection, payment and incurrence is variable and by excluding them from the calculation we are able to provide a more meaningful measure of our operations on a continuing basis. Our capital budgeting process is focused on programs to explore and develop our existing properties, accordingly, cash flows arising from acquisition and disposition activities are eliminated as we analyze these activities on a transaction by transaction basis separately from our analysis of the performance of our capital programs. Additions to other plant and equipment is primarily comprised of expenditures on corporate assets which do not generate incremental oil and natural gas production and are therefore analyzed separately from our evaluation of the performance of our exploration and development programs.

The following table reconciles cash flow used in investing activities to exploration and development expenditures.

	Three Months Ended September 30		Nine Months Ended September 30	
($ thousands)	**2020**	2019	**2020**	2019
Cash flow used in investing activities	**$ 16,288**	$ 150,651	**$ 233,092**	$ 447,835
Change in non-cash working capital	**(444)**	(11,577)	**(28,683)**	(46,646)
Proceeds from dispositions	**98**	150	**149**	1,100
Property acquisitions	**—**	(120)	**—**	(2,717)
Additions to other plant and equipment	**(40)**	(19)	**(2,027)**	(398)
Exploration and development expenditures	**$ 15,902**	$ 139,085	**$ 202,531**	$ 399,174

Free Cash Flow

We define free cash flow as adjusted funds flow less exploration and development expenditures (both non-GAAP measures defined above), payments on lease obligations and asset retirement obligations settled. We use free cash flow to evaluate funds available for debt repayment, common share repurchases, potential future dividends and acquisition opportunities.

The following table provides our computation of free cash flow.

	Three Months Ended September 30		Nine Months Ended September 30	
($ thousands)	**2020**	2019	**2020**	2019
Adjusted funds flow	**$ 78,508**	$ 213,379	**$ 229,330**	$ 670,279
Exploration and development expenditures	**(15,902)**	(139,085)	**(202,531)**	(399,174)
Payments on lease obligations	**(1,456)**	(1,390)	**(4,440)**	(4,402)
Asset retirement obligations settled	**(1,211)**	(1,134)	**(6,080)**	(10,860)
Free cash flow	**$ 59,939**	$ 71,770	**$ 16,279**	$ 255,843

Net Debt

We believe that net debt assists in providing a more complete understanding of our financial position and provides a key measure to assess our liquidity. We calculate net debt based on the principal amounts of our credit facilities and long-term notes outstanding, including trade and other payables, cash, and trade and other receivables. We use the principal amounts of the credit facilities and long-term notes outstanding in the calculation of net debt as these amounts represent our total repayment obligation at maturity. The carrying amount of debt issue costs associated with the credit facilities and long-term notes are excluded on the basis that these amounts have already been paid by Baytex at inception of the contract and do not represent an additional source of liquidity or repayment obligation.

The following table summarizes our calculation of net debt.

($ thousands)	**September 30, 2020**	December 31, 2019
Credit facilities(1)	**$ 624,826**	$ 506,471
Long-term notes(1)	**1,199,160**	1,337,200
Trade and other payables	**179,482**	207,454
Cash	**—**	(5,572)
Trade and other receivables	**(97,389)**	(173,762)
Net debt	**$ 1,906,079**	$ 1,871,791

(1) Principal amount of instruments expressed in Canadian dollars.

Operating Netback

We define operating netback as petroleum and natural gas sales, less blending expense, royalties, operating expense and transportation expense. Operating netback per boe is the operating netback divided by barrels of oil equivalent production volume for the applicable period. We believe that this measure assists in assessing our ability to generate cash margin on a unit of production basis and is a key measure used to evaluate our operating performance.

	Three Months Ended September 30		Nine Months Ended September 30	
($ thousands)	**2020**	2019	**2020**	2019
Petroleum and natural gas sales	**$ 252,538**	$ 424,600	**$ 741,841**	$ 1,360,024
Blending and other expense	**(10,673)**	(12,950)	**(37,490)**	(50,628)
Total sales, net of blending and other expense	**241,865**	411,650	**704,351**	1,309,396
Royalties	**(40,052)**	(75,017)	**(125,928)**	(242,959)
Operating expense	**(73,447)**	(97,377)	**(251,597)**	(298,143)
Transportation expense	**(6,372)**	(9,903)	**(21,745)**	(35,102)
Operating netback	**121,994**	229,353	**305,081**	733,192
Realized financial derivative (loss) gain	**(9,743)**	20,857	**30,731**	52,664
Operating netback after realized financial derivatives	**$ 112,251**	$ 250,210	**$ 335,812**	$ 785,856

Bank EBITDA

Bank EBITDA is used to assess compliance with certain financial covenants contained in our credit facility agreements. Net income is adjusted for the items set forth in the table below as prescribed by the credit facility agreements. The following table reconciles net income or loss to Bank EBITDA on a twelve month rolling basis.

	Twelve Months Ended September 30	
($ thousands)	**2020**	2019
Net income (loss)	**$ (2,777,896)**	$ (125,925)
Plus:		
Financing and interest	**126,228**	129,310
Unrealized foreign exchange (gain) loss	**3,776**	29,603
Unrealized financial derivatives (gain) loss	**32,470**	(150,933)
Current income tax expense	**1,382**	1,627
Deferred income tax expense (recovery)	**(315,078)**	(64,785)
Depletion and depreciation	**572,518**	745,578
Gain on dispositions	**(1,409)**	(1,257)
Transaction costs	**—**	8
Impairment	**2,904,171**	285,341
Non-cash items[(1)]	**18,619**	44,803
Bank EBITDA	**$ 564,781**	$ 893,370

(1) Non-cash items include share-based compensation, exploration and evaluation expense, note redemption premiums, interest on lease obligations, and non-cash other income.

INTERNAL CONTROL OVER FINANCIAL REPORTING

We are required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". This instrument requires us to disclose in our interim MD&A any weaknesses in or changes to our internal control over financial reporting during the period that may have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting. We confirm that no such weaknesses were identified in, or changes were made to, internal controls over financial reporting during the three months ended September 30, 2020.

FORWARD-LOOKING STATEMENTS

In the interest of providing our shareholders and potential investors with information regarding Baytex, including management's assessment of the Company's future plans and operations, certain statements in this document are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "plan", "project", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this document speak only as of the date of this document and are expressly qualified by this cautionary statement.

Specifically, this document contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; that the outlook for our industry is uncertain; our capital budget and expected average daily production for 2020; our expected royalty rate and operating, transportation, general and administrative and interest expenses for 2020; the existence, operation and strategy of our risk management program; that we committed to cost savings initiatives; the reassessment of our tax filings by the Canada Revenue Agency; our intention to defend the reassessments; our view of our tax filing position; that our internally generated adjusted funds flow and our existing undrawn credit facilities will provide sufficient liquidity to sustain our operations and planned capital expenditures; that a significant portion of our financial obligations will be funded by adjusted funds flow; we expect to remain in compliance with the financial covenants; that we expect to be delisted from the NSYE on December 3rd, 2020 and that we do not expect the delisting to affect our business operations or the listing and trading of our common shares on the TSX.

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices (well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices and price differentials (including the impacts of COVID-19); availability and cost of gathering, processing and pipeline systems; failure to comply with the covenants in our debt agreements; the availability and cost of capital or borrowing; that our credit facilities may not provide sufficient liquidity or may not be renewed; risks associated with a third-party operating our Eagle Ford properties; the cost of developing and operating our assets; depletion of our reserves; risks associated with the exploitation of our properties and our ability to acquire reserves; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; changes in government regulations that affect the oil and gas industry; regulations regarding the disposal of fluids; changes in environmental, health and safety regulations; public perception and its influence on the regulatory regime; restrictions or costs imposed by climate change initiatives; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; risks of counterparty default; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects; risks related to our thermal heavy oil projects; alternatives to and changing demand for petroleum products; risks associated with our use of information technology systems; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2019, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

Baytex Energy Corp.
Condensed Consolidated Statements of Financial Position
(thousands of Canadian dollars) (unaudited)

	Notes	As at September 30, 2020	December 31, 2019
ASSETS			
Current assets			
Cash		$ —	$ 5,572
Trade and other receivables		**97,389**	173,762
Financial derivatives	17	**41,746**	5,433
		139,135	184,767
Non-current assets			
Exploration and evaluation assets	5	**186,391**	320,210
Oil and gas properties	6	**2,798,198**	5,387,889
Other plant and equipment		**8,161**	7,598
Lease assets		**10,342**	13,619
Deferred income tax asset	14	**14,187**	—
		$ 3,156,414	$ 5,914,083
LIABILITIES			
Current liabilities			
Trade and other payables		**$ 179,482**	$ 207,454
Financial derivatives	17	**9,921**	8,668
Lease obligations		**5,791**	5,798
Asset retirement obligations	9	**10,913**	11,579
		206,107	233,499
Non-current liabilities			
Financial derivatives	17	**15,635**	—
Credit facilities	7	**622,654**	505,412
Long-term notes	8	**1,182,800**	1,328,175
Lease obligations		**4,703**	8,085
Asset retirement obligations	9	**740,238**	656,395
Deferred income tax liability		**—**	235,308
		2,772,137	2,966,874
SHAREHOLDERS' EQUITY			
Shareholders' capital	10	**5,729,164**	5,718,835
Contributed surplus		**14,356**	17,712
Accumulated other comprehensive income		**646,443**	556,224
Deficit		**(6,005,686)**	(3,345,562)
		384,277	2,947,209
		$ 3,156,414	$ 5,914,083

See accompanying notes to the condensed consolidated interim financial statements.

Baytex Energy Corp.
Condensed Consolidated Statements of Income (Loss) and Comprehensive Income (Loss)
(thousands of Canadian dollars, except per common share amounts and weighted average common shares) (unaudited)

		Three Months Ended September 30		Nine Months Ended September 30	
	Notes	**2020**	2019	**2020**	2019
Revenue, net of royalties					
Petroleum and natural gas sales	13	**$ 252,538**	$ 424,600	**$ 741,841**	$ 1,360,024
Royalties		**(40,052)**	(75,017)	**(125,928)**	(242,959)
		212,486	349,583	**615,913**	1,117,065
Expenses					
Operating		**73,447**	97,377	**251,597**	298,143
Transportation		**6,372**	9,903	**21,745**	35,102
Blending and other		**10,673**	12,950	**37,490**	50,628
General and administrative		**7,741**	9,934	**24,954**	35,576
Exploration and evaluation	5	**8,909**	2,138	**11,000**	8,667
Depletion and depreciation		**106,454**	180,422	**392,380**	551,548
Impairment	5, 6	**—**	—	**2,716,349**	—
Share-based compensation	11	**2,949**	3,401	**8,725**	14,245
Financing and interest	15	**27,962**	31,766	**97,412**	97,049
Financial derivatives loss (gain)	17	**17,027**	(28,523)	**(50,156)**	(21,742)
Foreign exchange (gain) loss	16	**(26,231)**	14,237	**27,688**	(37,978)
Gain on dispositions		**(98)**	(18)	**(246)**	(1,075)
Other income		**(293)**	(738)	**(2,300)**	(5,044)
		234,912	332,849	**3,536,638**	1,025,119
Net income (loss) before income taxes		**(22,426)**	16,734	**(2,920,725)**	91,946
Income tax expense (recovery)	14				
Current income tax expense		**322**	501	**880**	1,591
Deferred income tax expense (recovery)		**696**	1,082	**(261,481)**	(14,958)
		1,018	1,583	**(260,601)**	(13,367)
Net income (loss)		**$ (23,444)**	$ 15,151	**$ (2,660,124)**	$ 105,313
Other comprehensive income (loss)					
Foreign currency translation adjustment		**(30,268)**	25,344	**90,219**	(67,845)
Comprehensive income (loss)		**$ (53,712)**	$ 40,495	**$ (2,569,905)**	$ 37,468
Net income (loss) per common share	12				
Basic		**$ (0.04)**	$ 0.03	**$ (4.75)**	$ 0.19
Diluted		**$ (0.04)**	$ 0.03	**$ (4.75)**	$ 0.19
Weighted average common shares (000's)	12				
Basic		**561,128**	557,888	**560,484**	556,651
Diluted		**561,128**	560,888	**560,484**	560,438

See accompanying notes to the condensed consolidated interim financial statements.

Baytex Energy Corp.
Condensed Consolidated Statements of Changes in Equity
(thousands of Canadian dollars) (unaudited)

	Notes	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income	Deficit	**Total equity**
Balance at December 31, 2018		$ 5,701,516	$ 19,137	$ 667,874	$ (3,333,103)	**$ 3,055,424**
Vesting of share awards		15,721	(15,721)	—	—	**—**
Share-based compensation		—	14,245	—	—	**14,245**
Comprehensive income (loss)		—	—	(67,845)	105,313	**37,468**
Balance at September 30, 2019		$ 5,717,237	$ 17,661	$ 600,029	$ (3,227,790)	**$ 3,107,137**
Balance at December 31, 2019		$ 5,718,835	$ 17,712	$ 556,224	$ (3,345,562)	**$ 2,947,209**
Vesting of share awards	10	10,329	(10,329)	—	—	**—**
Share-based compensation	11	—	6,973	—	—	**6,973**
Comprehensive income (loss)		—	—	90,219	(2,660,124)	**(2,569,905)**
Balance at September 30, 2020		$ 5,729,164	$ 14,356	$ 646,443	$ (6,005,686)	**$ 384,277**

See accompanying notes to the condensed consolidated interim financial statements.

Baytex Energy Corp.
Condensed Consolidated Statements of Cash Flows
(thousands of Canadian dollars) (unaudited)

	Notes	Three Months Ended September 30 2020	Three Months Ended September 30 2019	Nine Months Ended September 30 2020	Nine Months Ended September 30 2019
CASH PROVIDED BY (USED IN):					
Operating activities					
Net income (loss) for the period		**$ (23,444)**	$ 15,151	**$ (2,660,124)**	$ 105,313
Adjustments for:					
Share-based compensation	11	**2,336**	3,401	**6,973**	14,245
Unrealized foreign exchange (gain) loss	16	**(25,880)**	13,855	**28,125**	(38,404)
Exploration and evaluation	5	**8,909**	2,138	**11,000**	8,667
Depletion and depreciation		**106,454**	180,422	**392,380**	551,548
Impairment	5, 6	**—**	—	**2,716,349**	—
Non-cash financing, accretion, and early redemption expense	15	**2,544**	5,014	**16,072**	14,021
Non-cash other income	9	**(293)**	—	**(293)**	—
Unrealized financial derivatives loss (gain)	17	**7,284**	(7,666)	**(19,425)**	30,922
Gain on dispositions		**(98)**	(18)	**(246)**	(1,075)
Deferred income tax expense (recovery)	14	**696**	1,082	**(261,481)**	(14,958)
Asset retirement obligations settled	9	**(1,211)**	(1,134)	**(6,080)**	(10,860)
Change in non-cash working capital		**16,391**	(17,275)	**78,829**	(59,499)
		93,688	194,970	**302,079**	599,920
Financing activities					
Increase (decrease) in credit facilities		**(75,944)**	155,199	**111,403**	50,445
Payments on lease obligations		**(1,456)**	(1,390)	**(4,440)**	(4,402)
Net proceeds from issuance of long-term notes	8	**—**	—	**652,150**	—
Redemption of long-term notes	8	**—**	(198,128)	**(833,672)**	(198,128)
		(77,400)	(44,319)	**(74,559)**	(152,085)
Investing activities					
Additions to exploration and evaluation assets	5	**(484)**	(1,047)	**(4,344)**	(2,441)
Additions to oil and gas properties	6	**(15,418)**	(138,038)	**(198,187)**	(396,733)
Additions to other plant and equipment		**(40)**	(19)	**(2,027)**	(398)
Property acquisitions		**—**	(120)	**—**	(2,717)
Proceeds from dispositions		**98**	150	**149**	1,100
Change in non-cash working capital		**(444)**	(11,577)	**(28,683)**	(46,646)
		(16,288)	(150,651)	**(233,092)**	(447,835)
Change in cash		**—**	—	**(5,572)**	—
Cash, beginning of period		**—**	—	**5,572**	—
Cash, end of period		**$ —**	$ —	**$ —**	$ —
Supplementary information					
Interest paid		**$ 3,365**	$ 22,315	**$ 55,145**	$ 78,493
Income taxes paid		**$ 1,155**	$ 76	**$ 1,155**	$ 1,158

See accompanying notes to the condensed consolidated interim financial statements.

1. REPORTING ENTITY

Baytex Energy Corp. (the “Company” or “Baytex”) is an oil and gas corporation engaged in the acquisition, development and production of oil and natural gas in the Western Canadian Sedimentary Basin and the United States. The Company’s common shares are traded on the Toronto Stock Exchange and the New York Stock Exchange under the symbol BTE. The Company’s head and principal office is located at 2800, 520 – 3rd Avenue S.W., Calgary, Alberta, T2P 0R3, and its registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

2. BASIS OF PRESENTATION

The condensed consolidated interim financial statements ("consolidated financial statements") have been prepared in accordance with International Accounting Standards 34, Interim Financial Reporting, under International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (the "IASB"). These consolidated financial statements do not include all the necessary annual disclosures as prescribed by IFRS and should be read in conjunction with the annual consolidated financial statements as at and for the year ended December 31, 2019.

The consolidated financial statements were approved by the Board of Directors of Baytex on November 2, 2020.

The consolidated financial statements have been prepared on a historical cost basis, with the exception of derivative financial instruments which have been measured at fair value. The consolidated financial statements are presented in Canadian dollars which is the functional currency of the Company. References to “US$” are to United States ("U.S.") dollars. All financial information is rounded to the nearest thousand, except per share amounts or when otherwise indicated.

The audited consolidated financial statements of the Company as at and for the year ended December 31, 2019 are available through its filings on SEDAR at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies, critical accounting judgments and significant estimates used in preparation of the 2019 annual financial statements have been applied in the preparation of these consolidated financial statements, except for the adoption of amendments to IFRS 3 *Business Combinations* as described below.

Current environment and estimation uncertainty

Management makes judgements and assumptions about the future in deriving estimates used in preparation of these consolidated financial statements in accordance with IFRS. Sources of estimation uncertainty include estimates used to determine economically recoverable oil, natural gas, and natural gas liquids reserves, the recoverable amount of long-lived assets or cash generating units, the fair value of financial derivatives, the provision for asset retirement obligations and the provision for income taxes and the related deferred tax assets and liabilities.

In March 2020, the World Health Organization declared a global pandemic related to the novel coronavirus ("COVID-19"). The emergence of COVID-19 and the steps taken by governments to control the spread of the virus resulted in significant instability in the global economy and a sharp decline in demand for crude oil. This combined with the increased supply of crude oil due to the Russia and Saudi Arabia price war resulted in an unprecedented collapse in global crude oil prices and significant volatility during Q2/2020. Global crude oil prices began to recover and were relatively stable during Q3/2020 as members of OPEC+ agreed to production curtailments and governments began to ease restrictions that allowed economies to begin reopening which increased demand. While these factors have resulted in recent improvements in crude oil prices the outlook for prices remains uncertain due to the potential for additional government restrictions from COVID-19 and uncertainty that members of OPEC+ will maintain production curtailments.

These factors have impacted our results for the nine months ended September 30, 2020. At March 31, 2020, we recorded a total impairment of $2.7 billion which included amounts related to our exploration and evaluation assets (note 5) and oil and gas properties (note 6). There is potential for further impairments or reversal of impairments over the balance of 2020 due to the current volatility in forecasted prices for the commodities we produce. In the current environment, assumptions and estimates regarding future commodity prices, the amount of economically recoverable reserves, exchange rates, and interest rates are subject to greater variability than normal. Actual results may differ from these estimates as the effect of future events cannot be determined with certainty.

We have taken action to protect our financial liquidity in response to the recent volatility in commodity prices and instability in the global economy. We have reduced our planned capital expenditures and have reduced production of oil and natural gas when commodity prices do not support economic production. We currently have $425.8 million of availability on our credit facilities and are currently forecasting to remain in compliance with the financial covenants applicable to our credit facilities for the foreseeable future at current forward commodity prices.

Business Combinations

Baytex adopted amendments to IFRS 3 *Business Combinations* effective January 1, 2020, which will be applied prospectively to acquisitions that occur on or after January 1, 2020. These amendments did not result in changes to the Company's accounting policies for applying the acquisition method but could result in future acquisitions being accounted for as an asset acquisition as opposed to a business combination.

4. SEGMENTED FINANCIAL INFORMATION

Baytex's reportable segments are determined based on the geographic location and nature of the underlying operations:

- Canada includes the exploration for, and the development and production of, crude oil and natural gas in Western Canada;
- U.S. includes the exploration for, and the development and production of, crude oil and natural gas in the U.S.; and
- Corporate includes corporate activities and items not allocated between operating segments.

	Canada		U.S.		Corporate		Consolidated	
Three Months Ended September 30	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 158,831**	$ 258,769	**$ 93,707**	$ 165,831	**$ —**	$ —	**$ 252,538**	$ 424,600
Royalties	**(12,297)**	(26,193)	**(27,755)**	(48,824)	**—**	—	**(40,052)**	(75,017)
	146,534	232,576	**65,952**	117,007	**—**	—	**212,486**	349,583
Expenses								
Operating	**57,557**	73,701	**15,890**	23,676	**—**	—	**73,447**	97,377
Transportation	**6,372**	9,903	**—**	—	**—**	—	**6,372**	9,903
Blending and other	**10,673**	12,950	**—**	—	**—**	—	**10,673**	12,950
General and administrative	**—**	—	**—**	—	**7,741**	9,934	**7,741**	9,934
Exploration and evaluation	**8,909**	2,138	**—**	—	**—**	—	**8,909**	2,138
Depletion and depreciation	**68,727**	115,008	**35,820**	63,356	**1,907**	2,058	**106,454**	180,422
Share-based compensation	**—**	—	**—**	—	**2,949**	3,401	**2,949**	3,401
Financing and interest	**—**	—	**—**	—	**27,962**	31,766	**27,962**	31,766
Financial derivatives loss (gain)	**—**	—	**—**	—	**17,027**	(28,523)	**17,027**	(28,523)
Foreign exchange (gain) loss	**—**	—	**—**	—	**(26,231)**	14,237	**(26,231)**	14,237
Gain on dispositions	**(98)**	(18)	**—**	—	**—**	—	**(98)**	(18)
Other (income) expense	**(694)**	—	**—**	—	**401**	(738)	**(293)**	(738)
	151,446	213,682	**51,710**	87,032	**31,756**	32,135	**234,912**	332,849
Net income (loss) before income taxes	**(4,912)**	18,894	**14,242**	29,975	**(31,756)**	(32,135)	**(22,426)**	16,734
Income tax expense (recovery)								
Current income tax expense	**—**	—	**322**	501	**—**	—	**322**	501
Deferred income tax expense (recovery)	**10,589**	4,734	**696**	(203)	**(10,589)**	(3,449)	**696**	1,082
	10,589	4,734	**1,018**	298	**(10,589)**	(3,449)	**1,018**	1,583
Net income (loss)	**$ (15,501)**	$ 14,160	**$ 13,224**	$ 29,677	**$ (21,167)**	$ (28,686)	**$ (23,444)**	$ 15,151
Total oil and natural gas capital expenditures[1]	**$ 3,784**	$ 96,744	**$ 12,020**	$ 42,311	**$ —**	$ —	**$ 15,804**	$ 139,055

	Canada		U.S.		Corporate		Consolidated	
Nine Months Ended September 30	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 427,000**	$ 817,506	**$ 314,841**	$ 542,518	**$ —**	$ —	**$ 741,841**	$ 1,360,024
Royalties	**(33,972)**	(82,313)	**(91,956)**	(160,646)	**—**	—	**(125,928)**	(242,959)
	393,028	735,193	**222,885**	381,872	**—**	—	**615,913**	1,117,065
Expenses								
Operating	**185,641**	221,680	**65,956**	76,463	**—**	—	**251,597**	298,143
Transportation	**21,745**	35,102	**—**	—	**—**	—	**21,745**	35,102
Blending and other	**37,490**	50,628	**—**	—	**—**	—	**37,490**	50,628
General and administrative	**—**	—	**—**	—	**24,954**	35,576	**24,954**	35,576
Exploration and evaluation	**11,000**	8,667	**—**	—	**—**	—	**11,000**	8,667
Depletion and depreciation	**249,125**	345,692	**137,462**	201,653	**5,793**	4,203	**392,380**	551,548
Impairment	**1,855,000**	—	**861,349**	—	**—**	—	**2,716,349**	—
Share-based compensation	**—**	—	**—**	—	**8,725**	14,245	**8,725**	14,245
Financing and interest	**—**	—	**—**	—	**97,412**	97,049	**97,412**	97,049
Financial derivatives (gain) loss	**—**	—	**—**	—	**(50,156)**	(21,742)	**(50,156)**	(21,742)
Foreign exchange loss (gain)	**—**	—	**—**	—	**27,688**	(37,978)	**27,688**	(37,978)
Gain on dispositions	**(246)**	(1,075)	**—**	—	**—**	—	**(246)**	(1,075)
Other income	**(694)**	—	**—**	—	**(1,606)**	(5,044)	**(2,300)**	(5,044)
	2,359,061	660,694	**1,064,767**	278,116	**112,810**	86,309	**3,536,638**	1,025,119
Net income (loss) before income taxes	**(1,966,033)**	74,499	**(841,882)**	103,756	**(112,810)**	(86,309)	**(2,920,725)**	91,946
Income tax expense (recovery)								
Current income tax expense	**469**	—	**411**	1,591	**—**	—	**880**	1,591
Deferred income tax (recovery) expense	**(74,687)**	8,842	**(164,298)**	4,505	**(22,496)**	(28,305)	**(261,481)**	(14,958)
	(74,218)	8,842	**(163,887)**	6,096	**(22,496)**	(28,305)	**(260,601)**	(13,367)
Net income (loss)	**$(1,891,815)**	$ 65,657	**$ (677,995)**	$ 97,660	**$ (90,314)**	$ (58,004)	**$(2,660,124)**	$ 105,313
Total oil and natural gas capital expenditures[(1)]	**$ 129,773**	$ 271,520	**$ 72,609**	$ 129,271	**$ —**	$ —	**$ 202,382**	$ 400,791

(1) Includes additions to exploration and evaluation assets, oil and gas properties, and property acquisitions, net of proceeds from divestitures.

	September 30, 2020	December 31, 2019
Canadian assets	**$ 1,526,819**	$ 3,484,123
U.S. assets	**1,569,346**	2,403,310
Corporate assets	**60,249**	26,650
Total consolidated assets	**$ 3,156,414**	$ 5,914,083

5. EXPLORATION AND EVALUATION ASSETS

	September 30, 2020	December 31, 2019
Balance, beginning of period	**$ 320,210**	$ 358,935
Capital expenditures	**4,344**	2,948
Property acquisitions	**—**	1,523
Divestitures	**—**	(443)
Property swaps	**479**	417
Impairment	**(127,861)**	(7,822)
Exploration and evaluation expense	**(11,000)**	(11,764)
Transfer to oil and gas properties (note 6)	**(5,830)**	(16,204)
Foreign currency translation	**6,049**	(7,380)
Balance, end of period	**$ 186,391**	$ 320,210

At September 30, 2020, there were no indicators of impairment or impairment reversal for exploration and evaluation assets in any of the Company's CGUs.

At March 31, 2020, the Company identified indicators of impairment for the exploration and evaluation assets within each of its six CGUs. The estimated recoverable amount was below the carrying value of the exploration and evaluation assets in the Conventional, Peace River, Lloydminster, Viking, and Eagle Ford CGUs and an impairment of $127.9 million was recorded as at March 31, 2020. The recoverable amount of each CGU was based on its fair value less costs of disposal ("FVLCD") and was estimated with reference to arm's length transactions in comparable locations and the discounted cash flows associated with the Company's future development plans. The following table indicates the impairment booked for each CGU at March 31, 2020.

	Impairment
Conventional CGU	$ 4,000
Peace River CGU	20,000
Lloydminster CGU	42,000
Viking CGU	13,000
Eagle Ford CGU	48,861
	$ 127,861

At December 31, 2019, the Company identified indicators of impairment for the exploration and evaluation assets within the Peace River CGU. The estimated recoverable amount was below the carrying value of the exploration and evaluation assets in the Peace River CGU and an impairment of $7.8 million was recorded as at December 31, 2019. There were no indicators of impairment for exploration and evaluation assets in the remaining CGUs at December 31, 2019.

6. OIL AND GAS PROPERTIES

		Cost	Accumulated depletion	Net book value
Balance, December 31, 2018	**$**	**10,744,533 $**	**(4,926,644) $**	**5,817,889**
Capital expenditures		549,343	—	549,343
Property acquisitions		2,636	—	2,636
Transfers from exploration and evaluation assets (note 5)		16,204	—	16,204
Change in asset retirement obligations (note 9)		23,894	—	23,894
Divestitures		(2,069)	1,690	(379)
Property swaps		1,773	—	1,773
Impairment		—	(180,000)	(180,000)
Foreign currency translation		(208,017)	89,813	(118,204)
Depletion		—	(725,267)	(725,267)
Balance, December 31, 2019	**$**	**11,128,297 $**	**(5,740,408) $**	**5,387,889**
Capital expenditures		198,187	—	198,187
Transfers from exploration and evaluation assets (note 5)		5,830	—	5,830
Change in asset retirement obligations (note 9)		82,900	—	82,900
Property swaps		(1,190)	178	(1,012)
Impairment		—	(2,588,488)	(2,588,488)
Foreign currency translation		101,173	(1,694)	99,479
Depletion		—	(386,587)	(386,587)
Balance, September 30, 2020	**$**	**11,515,197 $**	**(8,716,999) $**	**2,798,198**

At September 30, 2020, there were no indicators of impairment or impairment reversal for oil and gas properties in any of the Company's CGUs.

At March 31, 2020, the Company identified indicators of impairment for each of its six CGUs due to a significant decline in forecasted commodity prices. The recoverable amount was not sufficient to support the carrying amount which resulted in an impairment of $2.6 billion recorded at March 31, 2020. The recoverable amount of each CGU was based on its FVLCD which was estimated using a discounted cash flow model of proved plus probable cash flows from an independent reserve report prepared as at December 31, 2019 and was adjusted for operations between December 31, 2019 and March 31, 2020. The after-tax discount rates applied to the cash flows were between 8% and 14%.

The recoverable amount of the Company's CGUs were calculated at March 31, 2020 using the following benchmark reference prices for the years 2020 to 2029 adjusted for commodity differentials specific to the Company.

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
WTI crude oil (US$/bbl)	29.17	40.45	49.17	53.28	55.66	56.87	58.01	59.17	60.35	61.56
WCS heavy oil (CA$/bbl)	19.21	34.65	46.34	51.25	54.28	55.72	56.96	58.22	59.51	60.82
LLS crude oil (US$/bbl)	32.17	43.80	52.55	56.68	59.10	60.35	61.52	62.72	63.94	65.19
Edmonton par oil (CA$/bbl)	29.22	46.85	59.27	65.02	68.43	69.81	71.24	72.70	74.19	75.71
Henry Hub gas (US$/mmbtu)	2.10	2.58	2.79	2.86	2.93	3.00	3.07	3.13	3.19	3.25
AECO gas (CA$/mmbtu)	1.74	2.20	2.38	2.45	2.53	2.60	2.66	2.72	2.79	2.85
Exchange rate (CAD/USD)	1.41	1.37	1.34	1.34	1.34	1.33	1.33	1.33	1.33	1.33

This data is combined with assumptions relating to long-term prices, inflation rates and exchange rates together with estimates of transportation costs and pricing of competing fuels to forecast long-term energy prices, consistent with external sources of information. The prices and costs subsequent to 2029 have been adjusted for inflation at an annual rate of 2.0%.

The following table demonstrates the sensitivity of the estimated recoverable amount of the Company's CGUs to reasonably possible changes in key assumptions inherent in the estimate.

	Recoverable amount	Impairment	Change in discount rate of 1%	Change in oil price of $2.50/bbl	Change in gas price of $0.25/mcf
Conventional CGU	$ 37,444	$ 41,000	$ 3,000	$ 3,500	$ 8,500
Peace River CGU	109,631	345,000	9,500	53,500	3,000
Lloydminster CGU	227,967	470,000	25,000	69,500	—
Duvernay CGU	61,197	5,000	5,500	9,500	1,500
Viking CGU	962,134	915,000	57,000	123,000	4,000
Eagle Ford CGU	1,576,423	812,488	120,750	141,500	32,000
	$ 2,974,796	$ 2,588,488	$ 220,750	$ 400,500	$ 49,000

At December 31, 2019, the Company identified indicators of impairment for its Peace River CGU due to a sustained decline in Canadian heavy oil prices and a reduction in planned exploration and development expenditures related to thermal properties in the Peace River CGU. The recoverable amount of the Peace River CGU was based on its value-in-use ("VIU") which was estimated using a discounted cash flow model using proved plus probable cash flows from an independent reserve report prepared as at December 31,2019 and an after-tax discount rate of 11%. The recoverable amount was not sufficient to support the carrying amount of the CGU which resulted in an impairment of $180.0 million recorded as at December 31, 2019. There were no indicators of impairment or impairment reversal for the remaining CGUs as at December 31, 2019.

7. CREDIT FACILITIES

	September 30, 2020	December 31, 2019
Credit facilities - U.S. dollar denominated(1)	**$ 95,933**	$ 206,144
Credit facilities - Canadian dollar denominated	**528,893**	300,327
Credit facilities - principal	**624,826**	506,471
Unamortized debt issuance costs	**(2,172)**	(1,059)
Credit facilities	**$ 622,654**	$ 505,412

(1) U.S. dollar denominated credit facilities balance was US$72.0 million as at September 30, 2020 (December 31, 2019 - US$159.0 million).

Baytex has US$575 million of revolving credit facilities (the "Revolving Facilities") and a $300 million non-revolving secured term loan (the "Term Loan") (collectively the "Credit Facilities"). On March 3, 2020, Baytex amended its Credit Facilities to extend maturity from April 2, 2021 to April 2, 2024. These facilities will automatically be extended to June 4, 2024 providing Baytex has either refinanced, or has the ability to repay, the outstanding 2024 long-term notes with existing credit capacity as of April 1, 2024.

The extendible secured Revolving Facilities are comprised of a US$50 million operating loan and a US$325 million syndicated revolving loan for Baytex and a US$200 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc. The $300 million Term Loan is secured by the assets of Baytex's wholly-owned subsidiary, Baytex Energy Limited Partnership.

The Credit Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The Credit Facilities contain standard commercial covenants in addition to the financial covenants detailed below. There are no mandatory principal payments required prior to maturity which could be extended upon Baytex's request. Advances (including letters of credit) under the Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank’s prime lending rate, bankers’ acceptance discount rates or London Interbank Offered Rates, plus applicable margins. In the event that Baytex breaches any of the covenants under the Credit Facilities, Baytex may be required to repay, refinance or renegotiate the loan terms and may be restricted from taking on further debt or paying dividends to shareholders.

At September 30, 2020, Baytex had $15.5 million of outstanding letters of credit (December 31, 2019 - $15.2 million) under the Credit Facilities.

At September 30, 2020, Baytex was in compliance with all of the covenants contained in the Credit Facilities and is forecasting compliance with these covenants for the foreseeable future based on current forward commodity prices. A decrease or a sustained period of low commodity prices may result in non-compliance with our financial covenants and reduced liquidity on our existing credit facilities. Non-compliance with the financial covenants in our credit facilities could result in our debt becoming due and payable on demand.

The following table summarizes the financial covenants applicable to the Credit Facilities and Baytex's compliance therewith as at September 30, 2020.

Covenant Description	Position as at September 30, 2020	Covenant
Senior Secured Debt(1) to Bank EBITDA(2) (Maximum Ratio)	**1.1:1.0**	**3.5:1.0**
Interest Coverage(3) (Minimum Ratio)	**5.4:1.0**	**2.0:1.0**

(1) "Senior Secured Debt" is defined as the principal amount of the credit facilities and other secured obligations identified in the credit agreement. As at September 30, 2020, the Company's Senior Secured Debt totaled $640.3 million which includes $624.8 million of principal amounts outstanding and $15.5 million of letters of credit.

(2) "Bank EBITDA" is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expense, income tax, non-recurring losses, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration and evaluation expense, impairment, deferred income tax expense or recovery, unrealized gains and losses on financial derivatives and foreign exchange, and share-based compensation) and is calculated based on a trailing twelve month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the twelve months ended September 30, 2020 was $566.1 million.

(3) "Interest Coverage" is computed as the ratio of Bank EBITDA to financing and interest expense, excluding accretion of debt issue costs and asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expense, excluding accretion of debt issue costs and asset retirement obligations, for the twelve months ended September 30, 2020 was $105.2 million.

8. LONG-TERM NOTES

	September 30, 2020	December 31, 2019
5.125% notes (US$400,000 – principal) due June 1, 2021	**$ —**	$ 518,600
6.625% notes ($300,000 – principal) due July 19, 2022	**—**	300,000
5.625% notes (US$400,000 – principal) due June 1, 2024	**532,960**	518,600
8.75% notes (US$500,000 – principal) due April 1, 2027	**666,200**	—
Total long-term notes - principal(1)	**1,199,160**	1,337,200
Unamortized debt issuance costs	**(16,360)**	(9,025)
Total long-term notes - net of unamortized debt issuance costs	**$ 1,182,800**	$ 1,328,175

(1) The decrease in the principal amount of long-term notes outstanding from December 31, 2019 to September 30, 2020 is the result of principal repayments of $830.4 million, the issuance of $664.7 million aggregate principal amount and changes in the reported amount of U.S. dollar denominated debt of $27.6 million.

On February 5, 2020, Baytex issued US$500 million aggregate principal amount of senior unsecured notes due April 1, 2027 bearing interest at a rate of 8.75% per annum payable semi-annually (the "8.75% Senior Notes"). The 8.75% Senior Notes are redeemable at Baytex's option, in whole or in part, at specified redemption prices after April 1, 2023 and will be redeemable at par from April 1, 2026 to maturity. Transaction costs of $12.5 million were incurred in conjunction with the issuance which resulted in net proceeds of $652.2 million.

On February 20, 2020, Baytex used a portion of the net proceeds from the issuance of the 8.75% Senior Notes to complete the early redemption of the US$400 million principal amount of the 5.125% senior unsecured notes due June 1, 2021 at par plus accrued interest. The principal payment was $530.4 million.

On March 5, 2020, Baytex completed the early redemption of the $300 million principal amount of the 6.625% senior unsecured notes due July 19, 2022 at 101.104% of the principal amount, plus accrued interest. The principal payment was $300.0 million plus early redemption expense of $3.3 million.

The long-term notes do not contain any significant financial maintenance covenants. The long-term notes contain a debt incurrence covenant that restricts the Company's ability to raise additional debt beyond the existing Credit Facilities and long-term notes unless the Company maintains a minimum coverage ratio (computed as the ratio of Bank EBITDA (as defined in note 7) to financing and interest expense on a trailing twelve month basis) of 2.00:1.00. At September 30, 2020, the fixed charge coverage ratio was 5.0:1.0.

9. ASSET RETIREMENT OBLIGATIONS

	September 30, 2020	December 31, 2019
Balance, beginning of period	**$ 667,974**	$ 646,898
Liabilities incurred	**11,466**	21,748
Liabilities settled	**(6,080)**	(15,417)
Liabilities acquired from property acquisitions	**—**	1,648
Liabilities divested	**(116)**	(1,331)
Property swaps	**(514)**	792
Accretion (note 15)	**6,897**	13,713
Government grants(1)	**(694)**	—
Change in estimate	**(4,810)**	19,632
Changes in discount rates and inflation rates(2)	**76,244**	(17,486)
Foreign currency translation	**784**	(2,223)
Balance, end of period	**$ 751,151**	$ 667,974
Less current portion of asset retirement obligations	**10,913**	11,579
Non-current portion of asset retirement obligations	**$ 740,238**	$ 656,395

(1) During the three months ended September 30, 2020, Baytex recognized $0.7 million of non-cash other income and a reduction in asset retirement obligations related to government grants provided by the Government of Alberta and the Government of Saskatchewan.

(2) The discount and inflation rates at September 30, 2020 were 1.1% and 1.3%, respectively, compared to 1.8% and 1.4% at December 31, 2019.

10. SHAREHOLDERS' CAPITAL

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10.0 million preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. At September 30, 2020, no preferred shares have been issued by the Company and all common shares issued were fully paid.

The holders of common shares may receive dividends as declared from time to time and are entitled to one vote per share at any meeting of the holders of common shares. All common shares rank equally with regard to the Company's net assets in the event the Company is wound-up or terminated.

	Number of Common Shares (000s)	Amount
Balance, December 31, 2018	**554,060**	**$ 5,701,516**
Vesting of share awards	4,245	17,319
Balance, December 31, 2019	**558,305**	**$ 5,718,835**
Vesting of share awards	2,858	10,329
Balance, September 30, 2020	**561,163**	**$ 5,729,164**

11. SHARE AWARD INCENTIVE PLAN

The Company recorded compensation expense related to the share awards of $2.9 million and $8.7 million for the three and nine months ended September 30, 2020 ($3.4 million and $14.2 million for the three and nine months ended September 30, 2019) which includes $0.6 million and $1.8 million of cash compensation expense related to the incentive award plan and the associated equity total return swaps.

Share Award Plans

Baytex has a share award plan pursuant to which it issues restricted and performance awards. A restricted award entitles the holder of each award to receive one common share of Baytex at the time of vesting. A performance award entitles the holder of each award to receive between zero and two common shares on vesting; the number of common shares issued is determined by a multiplier. The multiplier, which ranges between zero and two, is calculated based on a number of factors determined and approved by the Board of Directors on an annual basis. The restricted awards and performance awards vest in equal tranches on the first, second and third anniversaries of the grant date.

The weighted average fair value of share awards granted was $1.48 per restricted and performance award for the nine months ended September 30, 2020 ($2.63 per restricted and performance award for the nine months ended September 30, 2019).

The number of share awards outstanding is detailed below:

(000s)	Number of restricted awards	Number of performance awards[1]	Total number of share awards
Balance, December 31, 2018	**3,243**	**3,273**	**6,516**
Granted	3,184	3,245	6,429
Vested and converted to common shares	(2,081)	(2,164)	(4,245)
Forfeited	(545)	(1,219)	(1,764)
Balance, December 31, 2019	**3,801**	**3,135**	**6,936**
Granted	2,239	3,253	5,492
Vested and converted to common shares	(1,717)	(1,141)	(2,858)
Forfeited	(140)	(185)	(325)
Balance, September 30, 2020	**4,183**	**5,062**	**9,245**

(1) Based on underlying awards before applying the payout multiplier which can range from 0x to 2x.

Incentive Award Plan

Baytex has a cash-settled incentive award plan (the "Incentive Award" plan) whereby the holder of each incentive award is entitled to receive a cash payment equal to the value of one Baytex common share at the time of vesting. The incentive awards vest in equal tranches on the first, second and third anniversaries of the grant date. The cumulative expense is recognized at fair value at each period end and is included in trade and other payables.

The Company uses equity total return swaps ("Equity TRS") on the equivalent number of Baytex common shares in order to fix the aggregate cost of the Incentive Award plan at the fair value determined on the grant date. The cumulative expense is recognized at fair value each period with realized gains or losses included in share-based compensation expense and unrealized gains or losses included in unrealized financial derivatives gain or loss. The carrying value of the financial derivatives includes the fair value of the Equity TRS which was a liability of $1.8 million on September 30, 2020.

During the nine months ended September 30, 2020, Baytex granted 2.9 million awards under the Incentive Award plan at a fair value of $1.50 per award.

Share Options

Baytex assumed share option plans pursuant to a business combination in 2018. No new grants will be made under the option plans.

The Company accounts for share options using the fair value method. Under this method, compensation is expensed over the vesting period for the share options, with a corresponding increase to contributed surplus.

Share options granted under the option plans had a maximum term of 3.5 years to expiry. One third of the options granted vest on each of the first, second, and third anniversaries of the date of grant. At September 30, 2020, 0.5 million options were outstanding with a weighted average remaining life of 0.4 years and a weighted average exercise price of $5.69 (December 31, 2019 - 2.5 million options with a weighted average exercise price of $6.83).

12. NET INCOME (LOSS) PER SHARE

Baytex calculates basic income or loss per share based on the net income or loss attributable to shareholders using the weighted average number of shares outstanding during the period. Diluted income or loss per share amounts reflect the potential dilution that could occur if share awards and share options were converted to common shares. The treasury stock method is used to determine the dilutive effect of share awards and share options whereby the potential conversion of share awards and share options and the amount of compensation expense, if any, attributed to future services are assumed to be used to purchase common shares at the average market price during the period.

	Three Months Ended September 30					
	2020			2019		
	Net loss	**Weighted average common shares (000s)**	**Net loss per share**	Net income	Weighted average common shares (000s)	Net income per share
Net income (loss) - basic	**$ (23,444)**	**561,128**	**$ (0.04)**	$ 15,151	557,888	$ 0.03
Dilutive effect of share awards	**—**	**—**	**—**	—	3,000	—
Dilutive effect of share options	**—**	**—**	**—**	—	—	—
Net income (loss) - diluted	**$ (23,444)**	**561,128**	**$ (0.04)**	$ 15,151	560,888	$ 0.03

	Nine Months Ended September 30					
	2020			2019		
	Net loss	**Weighted average common shares (000s)**	**Net loss per share**	Net income	Weighted average common shares (000s)	Net income per share
Net income (loss) - basic	**$ (2,660,124)**	**560,484**	**$ (4.75)**	$ 105,313	556,651	$ 0.19
Dilutive effect of share awards	**—**	**—**	**—**	—	3,787	—
Dilutive effect of share options	**—**	**—**	**—**	—	—	—
Net income (loss) - diluted	**$ (2,660,124)**	**560,484**	**$ (4.75)**	$ 105,313	560,438	$ 0.19

For the three and nine months ended September 30, 2020, all share awards and share options were excluded from the calculation of diluted earnings per share as their effect was anti-dilutive given the Company recorded a net loss. For the three and nine months ended September 30, 2019, no share awards were considered to be anti-dilutive and 3.4 million share options were excluded from the calculation of diluted earnings per share as they were determined to be anti-dilutive.

13. PETROLEUM AND NATURAL GAS SALES

Petroleum and natural gas sales from contracts with customers for the Company's Canadian and U.S. operating segments is set forth in the following table.

	Three Months Ended September 30					
	2020			2019		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 78,432**	**$ 75,620**	**$ 154,052**	$ 134,921	$ 140,344	$ 275,265
Heavy oil	**69,791**	**—**	**69,791**	117,961	—	117,961
NGL	**1,762**	**8,914**	**10,676**	1,486	11,045	12,531
Natural gas sales	**8,846**	**9,173**	**18,019**	4,401	14,442	18,843
Total petroleum and natural gas sales	**$ 158,831**	**$ 93,707**	**$ 252,538**	$ 258,769	$ 165,831	$ 424,600

	Nine Months Ended September 30					
	2020			2019		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 229,745**	**$ 257,818**	**$ 487,563**	$ 409,117	$ 442,763	$ 851,880
Heavy oil	**169,638**	**—**	**169,638**	381,684	—	381,684
NGL	**3,957**	**25,791**	**29,748**	6,684	47,656	54,340
Natural gas sales	**23,660**	**31,232**	**54,892**	20,021	52,099	72,120
Total petroleum and natural gas sales	**$ 427,000**	**$ 314,841**	**$ 741,841**	$ 817,506	$ 542,518	$ 1,360,024

Included in accounts receivable at September 30, 2020 is $70.4 million of accrued production revenue related to delivered volumes (December 31, 2019 - $138.0 million).

14. INCOME TAXES

The provision for income taxes has been computed as follows:

	Nine Months Ended September 30	
	2020	2019
Net loss before income taxes	**$ (2,920,725)**	$ 91,946
Expected income taxes at the statutory rate of 25.95% (2019 – 26.72%)	**(757,928)**	24,568
(Increase) decrease in income tax recovery resulting from:		
Share-based compensation	**1,809**	3,806
Effect of foreign exchange	**5,022**	(5,179)
Effect of change in income tax rates	**22,231**	(10,573)
Effect of rate adjustments for foreign jurisdictions	**35,982**	(20,965)
Effect of change in deferred tax benefit not recognized	**409,717**	(4,803)
Effect of U.S. tax change	**19,996**	—
Adjustments and assessments	**2,570**	(221)
Income tax recovery	**$ (260,601)**	$ (13,367)

On May 28, 2019 the Alberta government tabled legislation to decrease the corporate income tax rate from 12% to 8% over a multi-year period beginning July 1, 2019 and ending January 1, 2022. On June 29, 2020 the Alberta government announced that the corporate tax rate reduction to 8% previously scheduled for January 1, 2022 would be accelerated to July 1, 2020. Legislation enacting this accelerated timeline was enacted subsequent to quarter end and accordingly the effect is not reflected in the deferred tax recovery recorded for the nine months ended September 30, 2020.

At September 30, 2020, a deferred tax asset of $438.0 million remains unrecognized due to uncertainty surrounding future commodity prices (December 31, 2019 - $28.0 million).

As disclosed in the 2019 annual financial statements, in June 2016, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency (the “CRA”) that denied $591 million of non-capital loss deductions that relate to the calculation of income taxes for the years 2011 through 2015. In September 2016, Baytex filed notices of objection with the CRA appealing each reassessment received. There has been no change in the status of these reassessments since an Appeals Officer was assigned to the Company's file in July 2018. Baytex remains confident that the original tax filings are correct and intends to defend those tax filings through the appeals process.

On April 7, 2020, the U.S. Department of the Treasury and the IRS published final regulations addressing “anti-hybrid” rules under section 267A of the U.S. tax code and thus became substantially enacted. Pursuant to these regulations, the Company is no longer entitled to certain tax benefits previously recognized during 2019. Accordingly, a charge against deferred income taxes in the amount of $20.0 million was recorded in the nine months ended September 30, 2020.

15. FINANCING AND INTEREST

	Three Months Ended September 30		Nine Months Ended September 30	
	2020	2019	**2020**	2019
Interest on credit facilities	**$ 3,366**	$ 4,650	**$ 11,749**	$ 15,171
Interest on long-term notes	**21,943**	21,955	**69,231**	67,382
Interest on lease obligations	**109**	147	**360**	475
Non-cash financing	**756**	1,607	**5,863**	3,753
Accretion on asset retirement obligations (note 9)	**1,788**	3,407	**6,897**	10,268
Early redemption expense (note 8)	**—**	—	**3,312**	—
Financing and interest	**$ 27,962**	$ 31,766	**$ 97,412**	$ 97,049

16. FOREIGN EXCHANGE

	Three Months Ended September 30		Nine Months Ended September 30	
	2020	2019	**2020**	2019
Unrealized foreign exchange (gain) loss	**$ (25,880)**	$ 13,855	**$ 28,125**	$ (38,404)
Realized foreign exchange (gain) loss	**(351)**	382	**(437)**	426
Foreign exchange (gain) loss	**$ (26,231)**	$ 14,237	**$ 27,688**	$ (37,978)

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial assets and liabilities are comprised of cash, trade and other receivables, trade and other payables, financial derivatives, credit facilities, and long-term notes. The fair value of the credit facilities is equal to the principal amount outstanding as the credit facilities bear interest at floating rates and credit spreads that are indicative of market rates. The fair value of the long-term notes is determined based on market prices.

The carrying value and fair value of the Company's financial instruments carried on the condensed consolidated statements of financial position are classified into the following categories:

	September 30, 2020		December 31, 2019		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL					
Financial derivatives	**$ 41,746**	**$ 41,746**	$ 5,433	$ 5,433	Level 2
Total	**$ 41,746**	**$ 41,746**	$ 5,433	$ 5,433	
Financial assets at amortized cost					
Cash	**$ —**	**$ —**	$ 5,572	$ 5,572	—
Trade and other receivables	**97,389**	**97,389**	173,762	173,762	—
Total	**$ 97,389**	**$ 97,389**	$ 179,334	$ 179,334	
Financial Liabilities					
FVTPL					
Financial derivatives	**$ (25,556)**	**$ (25,556)**	$ (8,668)	$ (8,668)	Level 2
Total	**$ (25,556)**	**$ (25,556)**	$ (8,668)	$ (8,668)	
Financial liabilities at amortized cost					
Trade and other payables	**$ (179,482)**	**$ (179,482)**	$ (207,454)	$ (207,454)	—
Credit facilities	**(622,654)**	**(624,826)**	(505,412)	(506,471)	—
Long-term notes	**(1,182,800)**	**(586,526)**	(1,328,175)	(1,290,817)	Level 1
Total	**$ (1,984,936)**	**$ (1,390,834)**	$ (2,041,041)	$ (2,004,742)	

There were no transfers between Level 1 and Level 2 during the nine months ended September 30, 2020 and 2019.

Foreign Currency Risk

The carrying amounts of the Company's U.S. dollar denominated monetary assets and liabilities recorded in entities with a Canadian dollar functional currency at the reporting date are as follows:

	Assets		Liabilities	
	September 30, 2020	December 31, 2019	**September 30, 2020**	December 31, 2019
U.S. dollar denominated	**US$36,893**	US$8,733	**US$924,115**	US$841,961

Interest Rate Risk

Interest Rate Swaps

As of September 30, 2020, Baytex had an interest rate swap acquired in a business combination in 2018 outstanding with a notional value of $100 million maturing in October 2020, with a fixed contract price of 2.02% referencing the Canadian Dollar Offered Rate. At September 30, 2020, the fair value of the interest rate swap was a liability of $0.1 million (December 31, 2019 - nil).

Commodity Price Risk

Financial Derivative Contracts

Baytex had the following financial derivative contracts outstanding as of November 2, 2020:

	Remaining Period	Volume	Price/Unit(1)	Index
Oil				
Basis Swap	Oct 2020 to Dec 2020	6,500 bbl/d	WTI less US$16.27/bbl	WCS
Basis Swap	Jan 2021 to Jun 2021	2,000 bbl/d	WTI less US$13.75/bbl	WCS
Basis Swap	Jan 2021 to Dec 2021	4,000 bbl/d	WTI less US$14.26/bbl	WCS
Basis Swap(6)	Jan 2021 to Dec 2021	2,000 bbl/d	WTI less US$13.41/bbl	WCS
Basis Swap	Oct 2020 to Dec 2020	5,000 bbl/d	WTI less US$6.15/bbl	MSW
Basis Swap	Jan 2021 to Dec 2021	2,000 bbl/d	WTI less US$5.95/bbl	MSW
Basis Swap(6)	Jan 2021 to Dec 2021	4,000 bbl/d	WTI less US$4.78/bbl	MSW
Fixed - Sell	Oct 2020 to Dec 2020	8,000 bbl/d	US$42.78/bbl	WTI
3-way option(2)	Oct 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$56.00/US$61.35	WTI
3-way option(2)	Oct 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$57.00/US$60.00	WTI
3-way option(2)	Oct 2020 to Dec 2020	4,500 bbl/d	US$50.00/US$57.00/US$62.00	WTI
3-way option(2)	Oct 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$58.00/US$62.00	WTI
3-way option(2)	Oct 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$58.00/US$60.50	WTI
3-way option(2)	Oct 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$58.00/US$60.83	WTI
3-way option(2)	Oct 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$65.60	WTI
3-way option(2)	Oct 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$66.00	WTI
3-way option(2)	Oct 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$59.50/US$66.15	WTI
3-way option(2)	Oct 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$65.60	WTI
3-way option(2)	Oct 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.00	WTI
3-way option(2)	Oct 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.05	WTI
3-way option(2)	Oct 2020 to Dec 2020	2,000 bbl/d	US$51.00/US$60.00/US$66.70	WTI
3-way option(2)	Jan 2021 to Dec 2021	3,500 bbl/d	US$35.00/US$45.00/US$49.50	WTI
3-way option(2)	Jan 2021 to Dec 2021	10,000 bbl/d	US$35.00/US$45.00/US$55.00	WTI
Swaption(3)	Jan 2021 to Dec 2021	3,000 bbl/d	US$70.00/bbl	Brent
Swaption(3)	Jan 2021 to Dec 2021	3,000 bbl/d	US$60.75/bbl	WTI
Swaption(5)	Jan 2022 to Dec 2022	5,000 bbl/d	US$53.00/bbl	WTI
Swaption(5)	Jan 2022 to Dec 2022	5,000 bbl/d	US$54.00/bbl	WTI
Natural Gas				
Fixed - Sell	Oct 2020 to Dec 2020	10,500 GJ/d	$2.01/GJ	AECO 7A
Fixed - Sell	Jan 2021 to Jun 2021	3,000 GJ/d	$2.71/GJ	AECO 7A
Fixed - Sell	Jan 2021 to Dec 2021	16,000 GJ/d	$2.36/GJ	AECO 7A
Fixed - Sell	Oct 2020 to Dec 2020	2,500 GJ/d	$2.29/GJ	AECO 5A
Fixed - Sell	Jan 2021 to Dec 2021	2,500 GJ/d	$2.40/GJ	AECO 5A
Fixed - Sell	Oct 2020 to Dec 2020	5,500 mmbtu/d	US$2.64/mmbtu	NYMEX
Fixed - Sell	Jan 2021 to Dec 2021	12,000 mmbtu/d	US$2.70/mmbtu	NYMEX
3-way option(2)	Oct 2020 to Dec 2020	5,000 mmbtu/d	US$2.25/US$2.60/US$2.85	NYMEX
3-way option(2)(6)	Jan 2022 to Dec 2022	2,500 mmbtu/d	US$2.25/US$2.75/US$3.06	NYMEX
Swaption(4)	Jan 2021 to Dec 2021	5,000 mmbtu/d	US$2.90/mmbtu	NYMEX

(1) Based on the weighted average price per unit for the period.

(2) *Producer 3-way option consists of a sold put, bought put, and a sold call. To illustrate, in a US$50.00/US$58.00/US$62.00 contract, Baytex receives WTI plus US$8.00/bbl when WTI is at or below US$50.00/bbl; Baytex receives US$58.00/bbl when WTI is between US$50.00/bbl and US$58.00/bbl; Baytex receives the market price when WTI is between US$58.00/bbl and US$62.00/bbl; and Baytex receives US$62.00/bbl when WTI is above US$62.00/bbl.*
(3) *For these contracts, the counterparty has the right, if exercised on December 31, 2020, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.*
(4) *For these contracts, the counterparty has the right, if exercised on December 23, 2020, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.*
(5) *For these contracts, the counterparty has the right, if exercised on December 31, 2021, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.*
(6) *Contracts entered subsequent to September 30, 2020.*

The following table sets forth the realized and unrealized gains and losses recorded on financial derivatives.

	Three Months Ended September 30		Nine Months Ended September 30	
	2020	2019	**2020**	2019
Realized financial derivatives loss (gain)	**$ 9,743**	$ (20,857)	**$ (30,731)**	$ (52,664)
Unrealized financial derivatives loss (gain)	**7,284**	(7,666)	**(19,425)**	30,922
Financial derivatives loss (gain)	**$ 17,027**	$ (28,523)	**$ (50,156)**	$ (21,742)

Liquidity Risk

Liquidity risk is the risk that Baytex will encounter difficulty in meeting obligations associated with financial liabilities. Baytex manages its liquidity risk through cash and debt management. Such strategies include monitoring forecasted and actual cash flows from operating, financing and investing activities, available credit under existing banking arrangements, opportunities to issue additional common shares as well as reducing capital expenditures.

As at September 30, 2020, Baytex had unused capacity of $425.8 million on its Credit Facilities (December 31, 2019 - $523.8 million).

The timing of cash outflows relating to financial liabilities as at September 30, 2020 is outlined in the table below:

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	**$ 179,482**	$ 179,482	$ —	$ —	$ —
Credit facilities[(1)(2)]	**624,826**	—	—	624,826	—
Long-term notes[(2)]	**1,199,160**	—	—	532,960	666,200
Interest on long-term notes[(3)]	**489,037**	88,272	176,543	136,544	87,678
Lease obligations	**11,132**	6,086	4,449	597	—
	$ 2,503,637	**$ 273,840**	**$ 180,992**	**$ 1,294,927**	**$ 753,878**

(1) *At December 31, 2019, the credit facilities were set to mature on April 2, 2021. On March 3, 2020, Baytex amended the credit facilities to extend maturity to April 2, 2024 which will automatically be extended to June 4, 2024 providing the Company has either refinanced or has the ability to repay the outstanding 2024 long-term notes with existing credit capacity as of April 1, 2024.*
(2) *Principal amount of instruments. On February 5, 2020, Baytex issued US$500 million principal amount of 8.75% senior unsecured notes due 2027 and, on March 5, 2020, completed the redemption of $300 million principal amount of 6.625% senior unsecured notes due 2022 (note 8). On February 20, 2020 Baytex completed the redemption of the US$400 million principal amount of senior unsecured notes due 2021 (note 8).*
(3) *Excludes interest on credit facilities as interest payments on credit facilities fluctuate based on amounts outstanding and the prevailing interest rate at the time of borrowing.*

Credit Risk

Credit risk is the risk that a counterparty to a financial asset will default resulting in Baytex incurring a loss. As at September 30, 2020, the Company is exposed to credit risk with respect to its trade and other receivables and financial derivatives. Baytex manages these risks through the selection and monitoring of credit-worthy counterparties.

Most of the Company's trade and other receivables relate to petroleum and natural gas sales. Baytex reviews its exposure to individual entities on a regular basis and manages its credit risk by entering into sales contracts after reviewing the creditworthiness of the entity. Letters of credit or parental guarantees may be obtained prior to the commencement of business with certain counterparties. Credit risk may also arise from financial derivative instruments. The maximum exposure to credit risk is equal to the carrying value of the financial assets. The Company considers all financial assets that are not impaired or past due to be of good credit quality.

The majority of the Company's credit exposure on trade and other receivables at September 30, 2020 relates to accrued revenues and our financial derivative contracts. Accounts receivable from purchasers of the Company's petroleum and natural gas sales are typically collected on the 25th day of the month following production. Joint interest receivables are typically collected within one to three months following production. Included in trade and other receivables at September 30, 2020 is $70.4 million (December 31, 2019 - $138.0 million) of accrued petroleum and natural gas sales related to delivered volumes.

Should the Company determine that the ultimate collection of a receivable is in doubt, the carrying amount of trade and other receivables is reduced by adjusting the allowance for doubtful accounts and a charge to net income or loss. If the Company subsequently determines the accounts receivable is uncollectible, the receivable and allowance for doubtful accounts are adjusted accordingly. As at September 30, 2020, allowance for doubtful accounts was $2.1 million (December 31, 2019 - $1.6 million).

In determining whether amounts past due are collectible, the Company will assess the nature of the past due amounts as well as the credit worthiness and past payment history of the counterparty. As at September 30, 2020, trade and other receivables that Baytex has deemed past due (more than 90 days) but not impaired was $1.4 million (December 31, 2019 - $2.7 million). Baytex has estimated the lifetime expected credit loss as at and for the quarter ended September 30, 2020 to be nominal.

The Company's trade and other receivables, net of the allowance for doubtful accounts, were aged as follows as at September 30, 2020.

	September 30, 2020	December 31, 2019
Current (less than 30 days)	**$ 95,226**	$ 169,500
31-60 days	**561**	1,199
61-90 days	**240**	342
Past due (more than 90 days)	**1,362**	2,721
	$ 97,389	$ 173,762

ABBREVIATIONS

AECO	the natural gas storage facility located at Suffield, Alberta
bbl	barrel
bbl/d	barrel per day
*boe**	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
COSO	Committee of Sponsoring Organizations of the Treadway Commission
GAAP	generally accepted accounting principles
GJ	gigajoule
GJ/d	gigajoule per day
IAS	International Accounting Standard
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
LLS	Louisiana Light Sweet
mbbl	thousand barrels
*mboe**	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmBtu	million British Thermal Units
mmBtu/d	million British Thermal Units per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
TSX	Toronto Stock Exchange
WCS	Western Canadian Select
WTI	West Texas Intermediate

* *Oil equivalent amounts may be misleading, particularly if used in isolation. In accordance with NI 51-101, a boe conversion ratio for natural gas of 6 Mcf: 1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

CORPORATE INFORMATION

BOARD OF DIRECTORS

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Chair of the Board

Edward D. LaFehr
Director

Trudy M. Curran(2)(4)
Director

Naveen Dargan(1)(3)
Director

Don G. Hrap(3)
Director

Jennifer A. Maki(1)(2)
Director

Gregory K. Melchin(1)(4)
Director

David L. Pearce(3)(4)
Director

Steve D.L. Reynish
Director

(1) Member of the Audit Committee
(2) Member of the Human Resources and Compensation Committee
(3) Member of the Reserves and Sustainability Committee
(4) Member of the Nominating and Governance Committee

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OFFICERS

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Rodney D. Gray
Executive Vice President and
Chief Financial Officer

Brian G. Ector
Vice President, Capital Markets

Kendall D. Arthur
Vice President, Heavy Oil

Chad L. Kalmakoff
Vice President, Finance

Scott Lovett
Vice President, Corporate Development

Chad E. Lundberg
Vice President, Light Oil

AUDITORS

KPMG LLP

RESERVES ENGINEERS

McDaniel & Associates Consultants Ltd.

TRANSFER AGENT

Odyssey Trust Company

EXCHANGE LISTINGS

Toronto Stock Exchange
New York Stock Exchange
Symbol: BTE