BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the years ended December 31, 2019 and 2018
Dated March 3, 2020

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the years ended December 31, 2019 and 2018. This information is provided as of March 3, 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 months and year ended December 31, 2019 ("Q4/2019" and "2019") have been compared with the results for the three months and year ended December 31, 2018 ("Q4/2018" and "2018"). This MD&A should be read in conjunction with the Company's audited consolidated financial statements ("consolidated financial statements") for the years ended December 31, 2019 and 2018, together with the accompanying notes and the 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, and all tabular amounts are in thousands of Canadian dollars, except for percentages and per common share amounts or as otherwise noted.

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 the 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. 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.

STRATEGIC COMBINATION

On August 22, 2018, Baytex and Raging River Exploration Inc. ("Raging River") completed the strategic combination of the two companies (the "Strategic Combination") by way of a plan of arrangement whereby Baytex acquired all of the issued and outstanding common shares of Raging River. The Strategic Combination increased our light oil exposure and operational control of our properties while improving our leverage ratios. Production from Raging River's properties is approximately 90% light oil from the Viking and Duvernay. The addition of the primarily operated assets to our portfolio increased our inventory of drilling prospects and increased our ability to effectively allocate capital. Our comparative 2018 results include the results from Raging River from the closing date August 22, 2018.

2019 ANNUAL HIGHLIGHTS

Baytex delivered solid operating and financial results for 2019. Production of 97,680 boe/d for 2019 exceeded the top end of our 2019 annual guidance while exploration and development expenditures of $552.3 million were at the low end of guidance. Strong well performance along with the disciplined execution of our exploration and development program resulted in free cash flow of $328.8 million for 2019 which contributed to a $393.4 million decrease in net debt.

In Canada, production of 58,625 boe/d for 2019 was 15,243 boe/d higher than 43,382 boe/d in 2018 which reflects the impact of the Strategic Combination along with our exploration and development program. Exploration and development expenditures of $374.4 million were focused on our Viking light oil property along with additional heavy oil development at Peace River and Lloydminster. Exploration and development expenditures included costs associated with drilling 279 (247.8 net) light oil wells in the Viking and Duvernay along with 42 (42.0 net) heavy oil wells during 2019.

In the U.S., strong well performance from wells brought on stream during 2019 contributed to production of 39,055 boe/d which was 1,980 boe/d higher than 37,076 boe/d for 2018 despite relatively consistent completion activity in both periods. We invested $177.9 million on exploration and development activity during 2019 and drilled 96 (20.2 net) wells and commenced production from

109 (25.1 net) wells. During 2018 we drilled 91 (20.8 net) wells and commenced production from 120 (26.2 net) wells on our Eagle Ford properties.

In 2019, we benefited from narrower Canadian light and heavy oil differentials after production curtailments mandated by the Government of Alberta came into effect in January 2019. The Edmonton par light oil benchmark averaged $69.22/bbl in 2019 which represents a differential of US$4.86/bbl to the West Texas Intermediate ("WTI") benchmark price as compared to a US$11.30/bbl differential in 2018 and a US$26.51/bbl differential in Q4/2018. The Western Canadian Select ("WCS") heavy oil differential averaged US$12.75/bbl in 2019 relative to a differential of US$26.31/bbl in 2018 and a differential of US$39.42/bbl in Q4/2018. Stronger Canadian oil differentials helped to mitigate the impact of a lower WTI benchmark price which was US$57.03/bbl in 2019 compared to US$64.77/bbl during 2018.

We generated adjusted funds flow of $902.4 million in 2019 which was $429.4 million higher than $473.0 million for 2018. The increase is primarily due to a $277.4 million increase in operating netback driven by increased production from the Strategic Combination, strong well performance from our development program and tighter oil differentials on our Canadian production. Realized gains on financial derivatives of $75.6 million in 2019 also contributed to the increase in adjusted funds flow relative to 2018 when we recorded realized losses on financial derivatives of $73.2 million. The $429.4 million increase in adjusted funds flow contributed to the $312.9 million decrease in our net loss to $12.5 million for 2019 compared to a net loss of $325.3 million in 2018. In 2019, we recorded impairments of $187.8 million due to a sustained decline in Canadian heavy oil prices which resulted in a change in development plans for our thermal projects at Peace River compared to total impairments of $285.3 million in 2018 related to our Conventional and Eagle Ford assets.

Free cash flow of $328.8 million for 2019 reflects our strong operational and financial results along with the disciplined execution of our exploration and development program. Free cash flow generated in 2019 contributed to a $393.4 million decrease in net debt to $1,871.8 million at December 31, 2019, as compared to $2,265.2 million at December 31, 2018. Net debt also decreased due to a strengthening of the Canadian dollar at December 31, 2019 which reduced the reported amount of our U.S. dollar denominated net debt by $62.8 million relative to December 31, 2018.

2020 SENIOR NOTE FINANCING

On February 5, 2020, we issued US$500 million of senior unsecured notes bearing interest at 8.75% payable semi-annually which mature on April 1, 2027 (the "8.75% Senior Notes"). These 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.

On February 20, 2020, we used a portion of the net proceeds from the issuance of the 8.75% Senior Notes to redeem our US$400 million principal amount of our 5.125% senior unsecured notes due June 1, 2021 at par plus accrued interest. We also issued a redemption notice for the $300 million principal amount of our 6.625% senior unsecured notes due July 19, 2022 for early redemption on March 6, 2020 at 101.104% of the principal amount plus accrued interest. After completing the early redemption of the 6.625% senior unsecured notes our next unsecured debt maturity is June 1, 2024 when the US$400 million principal amount of 5.625% notes are due.

GUIDANCE

The following table compares our 2019 annual guidance compared to our 2019 results.

	Original guidance (1)	2019
Exploration and development expenditures ($ millions)	$550 - $650	$552.3
Production (boe/d)	93,000 - 97,000	97,680
Expenses:		
Royalty rate (%)	20.0	18.4
Operating ($/boe)	$10.75 - $11.25	$11.16
Transportation ($/boe)	$1.25 - $1.35	$1.23
General and administrative ($ millions)	~ $46 ($1.30/boe)	$45.5 ($1.28/boe)
Cash interest ($ millions)	~ $112 ($3.23/boe)	$107.4 ($3.01/boe)

(1) As announced on December 17, 2018. Includes updated guidance on May 2, 2019 for general and administrative expenses to reflect a change associated with the adoption of IFRS 16.

On December 4, 2019 our Board of Directors approved our 2020 capital budget of $500 - $575 million which is designed to generate production of 93,000 - 97,000 boe/d. The program is expected to be equally weighted between the first and second half of 2020 and we will maintain operational flexibility to adjust spending in response to commodity prices.

The following table summarizes our 2020 guidance as released on December 4, 2019.

	2020 Guidance
Exploration and development expenditures ($ millions)	$500 - $575 million
Production (boe/d)	93,000 - 97,000
Expenses:	
Royalty rate (%)	18.0 - 18.5
Operating ($/boe)	$11.25 - $12.00
Transportation ($/boe)	$1.20 - $1.30
General and administrative ($ millions)	$45 ($1.30/boe)
Cash interest ($ millions)	$112 ($3.23/boe)
Leasing expenditures ($ millions)	$7
Asset retirement obligations ($ millions)	$19

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

	Years Ended December 31					
	2019			2018		
Daily Production	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Liquids (bbl/d)						
Light oil and condensate	**22,358**	**21,229**	**43,587**	8,959	20,305	29,264
Heavy oil	**26,741**	**—**	**26,741**	25,954	—	25,954
Natural Gas Liquids ("NGL")	**1,364**	**8,865**	**10,229**	1,199	8,546	9,745
Total liquids (bbl/d)	**50,463**	**30,094**	**80,557**	36,112	28,851	64,963
Natural gas (mcf/d)	**48,969**	**53,773**	**102,742**	43,622	49,349	92,971
Total production (boe/d)	**58,625**	**39,055**	**97,680**	43,382	37,076	80,458
Production Mix						
Light oil and condensate	**38 %**	**54 %**	**45 %**	21 %	55 %	37 %
Heavy oil	**46 %**	**— %**	**27 %**	60 %	— %	32 %
NGL	**2 %**	**23 %**	**10 %**	3 %	23 %	12 %
Natural gas	**14 %**	**23 %**	**18 %**	16 %	22 %	19 %

Strong operational performance in 2019 resulted in production of 97,680 boe/d which exceeded the high end of our annual production guidance of 93,000 to 97,000 boe/d. Production for 2019 was 17,222 boe/d higher than 80,458 boe/d in 2018 due to the Strategic Combination along with production related to our exploration and development program.

In Canada, production of 58,625 boe/d in 2019 was up 35% from 43,382 boe/d in 2018. The increase in production in 2019 relative to 2018 is primarily due to the Strategic Combination along with strong well performance from our exploration and development program. Production from our Viking and Duvernay properties consists of approximately 90% light oil which resulted in a higher proportion of our Canadian production being comprised of light oil in 2019 compared to 2018.

U.S. production averaged 39,055 boe/d in 2019 which is up 5% from 37,076 boe/d for 2018. We experienced strong production results from wells brought on stream in 2019 which resulted a 1,980 boe/d increase in production compared to 2018 despite consistent completion activity in both periods. During 2019 we commenced production from 109 (25.1 net) wells compared to 120 (26.2 net) wells during 2018.

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 lower in 2019 as forecasted demand levels were impacted by the ongoing trade dispute between the U.S. and China which more than offset the effect of compliance with OPEC production curtailments along with U.S. imposed sanctions on Iran and Venezuela. North American benchmark prices for 2019 were lower than 2018 as a result of increasing supply from U.S. production along with uncertainty around future global demand for crude oil. Canadian oil differentials were tighter in 2019 compared to 2018 due to the Government of Alberta's production curtailments which came into effect in January of 2019. While our 2019 production levels were not significantly impacted by the Government of Alberta's curtailment program we benefited from narrower differentials for our Canadian light and heavy oil production in 2019.

We compare the price received for our U.S. crude oil production to the Louisiana Light Sweet ("LLS") stream at St. James, Louisiana, which is a representative benchmark for light oil pricing at the U.S. Gulf Coast. During 2019, the LLS benchmark averaged US$62.84/bbl representing a premium of US$5.81/bbl relative to WTI, compared to an LLS price of US$70.09/bbl or a premium of US$5.32/bbl to WTI for 2018.

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 $69.22/bbl for 2019 which is consistent with $69.31/bbl for 2018 despite the decline in WTI pricing over the same periods as differentials were tighter in 2019. Edmonton par traded at a US$4.86/bbl discount to WTI in 2019 compared to a US$11.30/bbl discount for 2018.

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. With curtailments, we benefited from a narrower WCS heavy oil differential in 2019 which averaged US$12.75/bbl in 2019 as compared to US$26.31/bbl for 2018. As a result, the WCS heavy oil benchmark price of $58.75/bbl increased $8.90/bbl from $49.85/bbl in 2018 despite a $8.28/bbl decrease in WTI (expressed in Canadian dollars) over the same periods.

Natural Gas

U.S. natural gas prices for 2019 were lower than 2018 as U.S. natural gas production has outpaced growth in natural gas demand. Canadian natural gas prices remained challenged during 2019 as a lack of egress from Western Canada continues to impact natural gas prices in the region.

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$2.63/mmbtu in 2019 which is lower than US$3.09/mmbtu in 2018. Record natural gas production levels in the U.S. have resulted in an oversupplied North American market and lower natural gas prices in 2019 relative to 2018.

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 $1.62/mcf during 2019 which is $0.08/mcf higher than the benchmark average of $1.54/mcf during 2018.

	Years Ended December 31		
	2019	2018	Change
Benchmark Averages			
WTI oil (US$/bbl)(1)	**57.03**	64.77	(7.74)
LLS oil (US$/bbl)(2)	**62.84**	70.09	(7.25)
LLS oil differential to WTI (US$/bbl)	**5.81**	5.32	0.49
Edmonton par oil ($/bbl)	**69.22**	69.31	(0.09)
Edmonton par oil differential to WTI (US$/bbl)	**(4.86)**	(11.30)	6.44
WCS heavy oil ($/bbl)(3)	**58.75**	49.85	8.90
WCS heavy oil differential to WTI (US$/bbl)	**(12.75)**	(26.31)	13.56
AECO natural gas price ($/mcf)(4)	**1.62**	1.54	0.08
NYMEX natural gas price (US$/mmbtu)(5)	**2.63**	3.09	(0.46)
CAD/USD average exchange rate	**1.3269**	1.2962	0.0307

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.
(2) LLS refers to the Argus trade month average for Louisiana Light Sweet oil.
(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.

	Years Ended December 31					
	2019			2018		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices[1]						
Light oil and condensate ($/bbl)	**$ 65.99**	**$ 77.46**	**$ 71.57**	$ 51.78	$ 85.96	$ 75.50
Heavy oil ($/bbl)[2]	**44.20**	**—**	**44.20**	36.20	—	36.20
NGL ($/bbl)	**16.93**	**18.74**	**18.50**	33.21	31.10	31.36
Natural gas ($/mcf)	**1.71**	**3.43**	**2.61**	1.48	4.20	2.92
Weighted average ($/boe)[2]	**$ 47.15**	**$ 51.08**	**$ 48.72**	$ 34.76	$ 59.83	$ 46.31

(1) Baytex's risk management strategy employs both oil and natural gas financial and physical forward contracts (fixed price forward sales and collars) and heavy oil differential physical delivery contracts (fixed price and percentage of WTI). The pricing information in this table excludes the impact of financial derivatives.

(2) 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 $48.72/boe for 2019 which is up $2.41/boe from $46.31/boe for 2018. Our realized price in the U.S. was $51.08/boe in 2019 which is $8.75/boe lower than $59.83/boe in 2018 due to the decrease in U.S. crude oil benchmark prices. In Canada, our realized price of $47.15/boe for 2019 was $12.39/boe higher than $34.76/boe for 2018. Canadian realized prices increased as narrower differentials improved heavy and light oil prices which more than offset the impact of a lower WTI price and we had a higher proportion of light oil from the Strategic Combination.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Our realized light oil and condensate price in 2019 was $65.99/bbl representing a discount of $3.23/bbl to the Edmonton par benchmark compared to 2018 when our realized price was $51.78/bbl or a discount of $17.53/bbl. The majority of our 2018 light oil production occurred after closing of the Strategic Combination and was impacted by a sharp widening of Canadian oil differentials in Q4/2018 which resulted in a wider discount to the Edmonton par benchmark reported for the annual period. The discount of $3.23/bbl for 2019 is relatively consistent with our realized Q4/2018 discount of $2.14/bbl to Edmonton par.

We compare the price received for our U.S. light oil and condensate production to the LLS benchmark. Our realized light oil and condensate price averaged $77.46/bbl for 2019 compared to $85.96/bbl for 2018. Expressed in U.S. dollars, our realized light oil and condensate price of US$58.38/bbl for 2019 reflects a US$4.46/bbl discount to the LLS benchmark for 2019 compared to a discount of US$3.77/bbl in 2018. In 2019, our price realizations relative to LLS was impacted by a change in certain marketing contracts to be priced on the Magellan East Houston ("MEH") benchmark which represents light oil pricing at the Magellan East crude oil terminal in Houston, Texas. In 2020, we expect to compare our realized light oil price to the MEH benchmark as the majority of our light oil and condensate contracts are now referenced to the MEH benchmark price.

Our realized heavy oil price, net of blending and other expense averaged $44.20/bbl in 2019 compared to $36.20/bbl in 2018. The $8.00/bbl increase in our realized heavy oil price for 2019 is fairly consistent with the $8.90/bbl increase in the WCS benchmark from 2018. Our realized heavy oil price did not increase as much as the WCS benchmark due to certain WTI based heavy oil rail contracts that were entered into prior to the Government of Alberta's decision to curtail production which resulted in a narrowing of the WCS differential.

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 of the underlying products. Our realized NGL price was $18.50/bbl in 2019 or 24% of WTI (expressed in Canadian dollars) compared to $31.36/bbl or 37% of WTI (expressed in Canadian dollars) in 2018. The decrease in our NGL price for 2019 is consistent with the increase in the production and supply of NGLs in North America which resulted in lower market prices for propane and butane relative to 2018.

We compare our realized natural gas price in Canada to the AECO benchmark price. Our realized natural gas price for 2019 was $1.71/mcf compared to $1.48/mcf in 2018. The $0.23/mcf increase in our realized natural gas price in 2019 is higher than the $0.08/mcf increase in the AECO natural gas price over the same period as the natural gas in our Viking asset acquired in the Strategic Combination received higher natural gas pricing relative to our legacy Baytex properties in Canada. In the U.S., our realized natural gas price was US$2.58/mmbtu for 2019 compared to US$3.24/mmbtu in 2018. Our realized natural gas price in the U.S. is relatively consistent with the NYMEX benchmark in 2019 and 2018.

Petroleum and Natural Gas Sales

	Years Ended December 31					
	2019			2018		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 538,487**	**$ 600,163**	**$ 1,138,650**	$ 169,335	$ 637,055	$ 806,390
Heavy oil	**500,187**	**—**	**500,187**	411,794	—	411,794
NGL	**8,430**	**60,647**	**69,077**	14,531	97,008	111,539
Total liquids sales	**1,047,104**	**660,810**	**1,707,914**	595,660	734,063	1,329,723
Natural gas sales	**30,620**	**67,385**	**98,005**	23,555	75,592	99,147
Total petroleum and natural gas sales	**1,077,724**	**728,195**	**1,805,919**	619,215	809,655	1,428,870
Blending and other expense	**(68,795)**	**—**	**(68,795)**	(68,832)	—	(68,832)
Total sales, net of blending and other expense	**$ 1,008,929**	**$ 728,195**	**$ 1,737,124**	$ 550,383	$ 809,655	$ 1,360,038

Total sales, net of blending and other expense, of $1,737.1 million for 2019 increased $377.1 million from $1,360.0 million reported for 2018. Total sales, net of blending and other expense, was higher in 2019 due to production from the Strategic Combination along with strong operational results from our exploration and development program and from a $2.41/boe increase in our weighted average realized price compared to 2018.

In Canada, total sales, net of blending and other expense, was $1,008.9 million for 2019 which is an increase of $458.5 million from $550.4 million reported for 2018. Total petroleum and natural gas sales increased with production from the Strategic Combination and our exploration and development program. The 15,243 boe/d increase in production for 2019 resulted in a $193.4 million increase in total sales, net of blending and other expense, relative to 2018. Our average realized price for 2019 was $12.39/boe higher than 2018 as a result of stronger heavy and light oil and condensate price realizations from narrower oil differentials. The increase in our realized price in 2019 resulted in a $265.1 million increase in total sales, net of blending and other expense, relative to 2018.

In the U.S., petroleum and natural gas sales were $728.2 million for 2019 which is a decrease of $81.5 million from $809.7 million reported for 2018. Our realized price for 2019 was $8.75/boe lower due to the decline in U.S. benchmark prices and resulted in a $124.7 million decrease in total petroleum and natural gas sales relative to 2018. The decrease in total sales due to lower realized pricing was partially offset by a 1,979 boe/d increase in production in 2019 which resulted in a $43.2 million increase in total sales compared to 2018.

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.

	Years Ended December 31					
	2019			2018		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 107,467**	**$ 212,774**	**$ 320,241**	$ 72,700	$ 241,054	$ 313,754
Average royalty rate(1)	**10.7 %**	**29.2 %**	**18.4 %**	13.2 %	29.8 %	23.1 %
Royalty rate per boe	**$ 5.02**	**$ 14.93**	**$ 8.98**	$ 4.59	$ 17.81	$ 10.68

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

Total royalties for 2019 were $320.2 million or 18.4% of total sales, net of blending and other expense, compared to $313.8 million or 23.1% in 2018. Our average royalty rate of 18.4% for 2019 is below our annual guidance of approximately 20.0% and decreased from 2018 mainly due to the Strategic Combination.

In Canada, total royalties were $107.5 million or 10.7% of sales, net of blending and other expense, for 2019 compared to $72.7 million or 13.2% of sales, net of blending and other expense, in 2018. Our overall royalty rate in Canada decreased following the Strategic Combination due to the lower royalty rate on our Viking and Duvernay properties as compared to our heavy oil properties. Total royalties of $107.5 million in 2019 were higher than $72.7 million in 2018 due to the increase in total sales, net of blending and other expense.

Total royalties in the U.S. were $212.8 million or 29.2% of sales for 2019 compared to $241.1 million or 29.8% of sales reported for 2018. The royalty rate on our U.S. production does not vary with price but can vary across our acreage. Royalties for 2019 averaged 29.2% of petroleum and natural gas sales which is consistent with 29.8% for 2018. The decrease in total royalties in 2019 compared to 2018 is consistent with the decrease in total petroleum and natural gas sales over the same period.

Operating Expense

	Years Ended December 31					
	2019			2018		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 298,303**	**$ 99,413**	**$ 397,716**	$ 221,717	$ 89,875	$ 311,592
Operating expense per boe	**$ 13.94**	**$ 6.97**	**$ 11.16**	$ 14.00	$ 6.64	$ 10.61

Operating expense was $397.7 million ($11.16/boe) in 2019 compared to $311.6 million ($10.61/boe) for 2018. The increase in total operating expense can be attributed to higher production in 2019 along with an increase in the proportion of our annual production from Canada relative to 2018. Operating expense of $11.16/boe for 2019 is consistent with expectations and is within our 2019 annual guidance range of $10.75 - $11.25/boe.

In Canada, operating expense was $298.3 million ($13.94/boe) for 2019 compared to $221.7 million ($14.00/boe) for 2018. The increase in total operating expense in Canada is a result of the additional production from the Strategic Combination as our per unit operating expense of $13.94/boe is consistent with $14.00/boe in 2018. U.S. operating expense was $99.4 million ($6.97/boe) for 2019 compared to $89.9 million ($6.64/boe) for 2018. The increase in total operating expense reflects higher U.S. production combined with a weaker Canadian dollar during 2019 compared to 2018. Expressed in U.S. dollars, per boe operating expense of US$5.25/boe in 2019 is consistent with US$5.12/boe in 2018.

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.

	Years Ended December 31					
	2019			2018		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 43,942**	**$ —**	**$ 43,942**	$ 36,869	$ —	$ 36,869
Transportation expense per boe	**$ 2.05**	**$ —**	**$ 1.23**	$ 2.33	$ —	$ 1.26

We reported transportation expense of $1.23/boe for 2019 which is slightly below our annual guidance range of $1.25 - $1.35/boe for 2019. Transportation expense was $43.9 million ($1.23/boe) for 2019 was higher than $36.9 million ($1.26/boe) for 2018 and reflects additional oil trucking and transportation costs associated with our Viking and Duvernay light oil properties acquired as part of the Strategic Combination.

Blending and Other Expense

Blending and other expense primarily includes the cost of blending diluent purchased in order to reduce the viscosity of our heavy oil transported through pipelines 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. Accordingly, our heavy oil sales price realization can fluctuate depending on the quantity and price of blending diluent required to meet pipeline specifications.

Blending and other expense was $68.8 million for 2019 and 2018 as total blending volumes and prices were relatively consistent in both periods.

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.

	Years Ended December 31		
($ thousands)	**2019**	2018	Change
Realized financial derivatives gain (loss)			
Crude oil	**$ 72,052**	$ (74,902)	$ 146,954
Natural gas	**3,577**	1,765	1,812
Interest and financing	**(9)**	(28)	19
Total	**75,620**	(73,165)	148,785
Unrealized financial derivatives gain (loss)			
Crude oil	**(80,602)**	117,087	(197,689)
Natural gas	**(1,857)**	(697)	(1,160)
Interest and financing	**(358)**	325	(683)
Total	**(82,817)**	116,715	(199,532)
Total financial derivatives gain (loss)			
Crude oil	**(8,550)**	42,185	(50,735)
Natural gas	**1,720**	1,068	652
Interest and financing	**(367)**	297	(664)
Total	**$ (7,197)**	$ 43,550	$ (50,747)

We recorded a total financial derivatives loss of $7.2 million for 2019. Realized financial derivatives gains of $75.6 million for 2019 were primarily a result of the market prices for crude oil settling at levels below those set in our derivative contracts. The unrealized loss on financial derivatives of $82.8 million for 2019 reflects the realization of our net financial derivatives asset recorded at December 31, 2018 along with changes in the fair value of our contracts entered for 2020.

Realized gains on crude oil financial derivatives of $72.1 million in 2019 are a result of market prices for Brent and WTI settling at levels below the prices set in our contracts outstanding during the period. Our natural gas financial derivatives generated gains of $3.6 million and were a result of the NYMEX index averaging less that the fixed price on our NYMEX contracts in place for 2019.

Unrealized losses of $82.8 million recorded for 2019 reflects the decrease in the fair value of our net unrealized financial derivatives position from December 31, 2018. At December 31, 2018, our net asset of $79.6 million was primarily associated with contracts for 2019 which generated realized gains of $75.6 million during 2019. The unrealized loss for 2019 also reflects changes in value for our 2020 financial derivative contracts which resulted in a net liability of $3.2 million at December 31, 2019.

We had the following commodity financial derivative contracts as at March 3, 2020.

	Remaining Period	Volume	Price/Unit (1)	Index
Oil				
Basis swap	Jan 2020 to Dec 2020	2,500 bbl/d	WTI less US$16.10/bbl	WCS
Basis swap (6)	Apr 2020 to Dec 2020	4,000 bbl/d	WTI less US$16.38/bbl	WCS
Basis swap	Jan 2020 to Dec 2020	2,000 bbl/d	WTI less US$6.50/bbl	MSW
Basis swap (6)	Apr 2020 to Dec 2020	3,000 bbl/d	WTI less US$5.92/bbl	MSW
Fixed - Sell	Jan 2020 to Mar 2020	6,000 bbl/d	US$56.60/bbl	WTI
Fixed - Sell	Jan 2020 to Dec 2020	2,000 bbl/d	US$58.00/bbl	WTI
3-way option (2)	Jan 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$56.00/US$61.35	WTI
3-way option (2)	Jan 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$57.00/US$60.00	WTI
3-way option (2)	Jan 2020 to Dec 2020	4,500 bbl/d	US$50.00/US$57.00/US$62.00	WTI
3-way option (2)	Jan 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$58.00/US$62.00	WTI
3-way option (2)	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$58.00/US$60.50	WTI
3-way option (2)	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$58.00/US$60.83	WTI
3-way option (2)	Jan 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$65.60	WTI
3-way option (2)	Jan 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$66.00	WTI
3-way option (2)	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$59.50/US$66.15	WTI
3-way option (2)	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$65.60	WTI
3-way option (2)	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.00	WTI
3-way option (2)	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.05	WTI
3-way option (2)	Jan 2020 to Dec 2020	2,000 bbl/d	US$51.00/US$60.00/US$66.70	WTI
Swaption (3)	Jan 2021 to Dec 2021	3,000 bbl/d	US$64.50/bbl	Brent
Swaption (4)	Jan 2021 to Dec 2021	3,000 bbl/d	US$70.00/bbl	Brent
Swaption (4)	Jan 2021 to Dec 2021	3,000 bbl/d	US$60.75/bbl	WTI
Natural Gas				
3-way option (2)	Jan 2020 to Dec 2020	5,000 mmbtu/d	US$2.25/US$2.60/US$2.85	NYMEX
Swaption (5)	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 call, a bought put and a sold put. 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 September 30, 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 31, 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 23, 2020, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.
(6) Contracts entered subsequent to December 31, 2019.

Operating Netback

	Years Ended December 31					
	2019			2018		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**58,625**	**39,055**	**97,680**	43,382	37,076	80,458
Operating netback:						
Total sales, net of blending and other expense	**$ 47.15**	**$ 51.08**	**$ 48.72**	$ 34.76	$ 59.83	$ 46.31
Royalties	**(5.02)**	**(14.93)**	**(8.98)**	(4.59)	(17.81)	(10.68)
Operating expense	**(13.94)**	**(6.97)**	**(11.16)**	(14.00)	(6.64)	(10.61)
Transportation expense	**(2.05)**	**—**	**(1.23)**	(2.33)	—	(1.26)
Operating netback	**$ 26.14**	**$ 29.18**	**$ 27.35**	$ 13.84	$ 35.38	$ 23.76
Realized financial derivatives gain (loss)	**—**	**—**	**2.12**	—	—	(2.49)
Operating netback after financial derivatives	**$ 26.14**	**$ 29.18**	**$ 29.47**	$ 13.84	$ 35.38	$ 21.27

Operating netback after financial derivatives of $29.47/boe increased $8.20/boe from $21.27/boe for 2018. Operating netback of $27.35/boe for 2019 was $3.59/boe higher than $23.76/boe for 2018 due to stronger realized pricing as a result of narrower light and heavy oil differentials relative to 2018. We recorded realized gains on financial derivatives of $2.12/boe in 2019 which resulted in a $4.61/boe increase in operating netback after financial derivatives compared to 2018 when we recorded losses of $2.49/boe.

In Canada, our operating netback was $26.14/boe in 2019 compared to $13.84/boe in 2018. The increase in our operating netback in Canada was driven by stronger realized pricing due the increase in light oil production following the Strategic Combination along with narrower Canadian oil differentials in 2019 relative to 2018. Our operating netback in the U.S. of $29.18/boe in 2019 was lower than $35.38/boe in 2018 due to the impact of lower U.S. benchmark prices on our realized sales price.

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 capital and production activities on behalf of our working interest partners. G&A expense fluctuates with head office staffing levels and the level of operated capital and production activity during the period.

	Years Ended December 31		
($ thousands except for per boe)	**2019**	2018	Change
Gross general and administrative expense	**$ 51,660**	$ 56,318	$ (4,658)
Overhead recoveries	**(6,191)**	(10,493)	4,302
General and administrative expense	**$ 45,469**	$ 45,825	$ (356)
General and administrative expense per boe	**$ 1.28**	$ 1.56	$ (0.28)

We reported G&A expense of $45.5 million ($1.28/boe) compared to $45.8 million ($1.56/boe) for 2018. G&A expense for 2019 was in line with expectations and our annual guidance of approximately $46 million ($1.30/boe).

G&A expense of $45.5 million ($1.28/boe) for 2019 is slightly lower than $45.8 million ($1.56/boe) for 2018 which only includes the additional staff and costs associated with the Strategic Combination following closing on August 22, 2018. In 2019 we continued to optimize our business following integration of the two companies which resulted in a decrease in G&A expense per boe in 2019 relative to 2018 and reflects the efficiencies we were able to realize by combining the two organizations. A $4.1 million decrease in rent expense in 2019 relative to 2018 was primarily due to the change in the accounting for leases which resulted in a change to the presentation of payments for office leases.

Financing and Interest Expense

Financing and interest expense includes interest on our bank loan, long-term notes and lease obligations as well as non-cash financing costs and the accretion on our asset retirement obligations. Financing and interest expense varies depending on debt levels outstanding during the period and 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.

	Years Ended December 31		
($ thousands except for per boe)	**2019**	2018	Change
Interest on bank loan	**$ 20,376**	$ 15,637	$ 4,739
Interest on long-term notes	**86,431**	88,681	(2,250)
Interest on lease obligations	**610**	—	610
Cash financing and interest expense	**107,417**	104,318	3,099
Accretion of debt issue costs	**4,735**	3,854	881
Accretion of asset retirement obligation	**13,713**	10,914	2,799
Financing and interest expense	**$ 125,865**	$ 119,086	$ 6,779
Cash interest per boe	**$ 3.01**	$ 3.55	$ (0.54)
Financing and interest expense per boe	**$ 3.53**	$ 4.06	$ (0.53)

We reported financing and interest expense of $125.9 million ($3.53/boe) for 2019 compared to $119.1 million ($4.06/boe) for 2018. Cash interest expense of $107.4 million ($3.01/boe) for 2019 was below our 2019 annual guidance of approximately $112 million ($3.23/boe). We allocated our free cash flow to debt reduction and redeemed the US$150 million principal amount of 6.75% senior unsecured notes in September of 2019 and reduced borrowings on our credit facilities throughout 2019 which resulted in lower cash interest expense relative to our annual guidance.

Financing and interest expense was $125.9 million for 2019 which is $6.8 million higher than $119.1 million reported for 2018. Interest on our bank loan of $20.4 million in 2019 increased $4.7 million relative to $15.6 million in 2018 due to the increase in loan balances following the assumption of net debt associated with the Strategic Combination. The weighted average interest rate on the credit facilities for 2019 was 4.0% as compared to 4.3% for 2018. We redeemed the US$150 million principal amount of 6.75% senior unsecured notes on September 13, 2019 which resulted in lower interest on our long-term notes in 2019 compared to 2018. Total accretion was higher in 2019 as our asset retirement obligation increased with the Strategic Combination.

Exploration and Evaluation Expense

Exploration and evaluation ("E&E") expense is related to the expiry of leases and the derecognition of costs for exploration programs that have not demonstrated commercial viability and technical feasibility. E&E expense will vary depending on the timing of lease expiries, the accumulated costs of expiring leases, and the economic facts and circumstances related to the Company's exploration programs. E&E expense was $11.8 million for 2019 compared to $21.7 million for 2018.

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.

	Years Ended December 31		
($ thousands except for per boe)	**2019**	2018	Change
Depletion	**$ 725,267**	$ 556,634	$ 168,633
Depreciation	**6,419**	2,050	4,369
Depletion and depreciation	**$ 731,686**	$ 558,684	$ 173,002
Depletion and depreciation per boe	**$ 20.52**	$ 19.02	$ 1.50

Depletion and depreciation expense was $731.7 million ($20.52/boe) for 2019 compared to $558.7 million ($19.02/boe) reported for 2018. Total depletion and depreciation expense was higher in 2019 due to the Strategic Combination which resulted in a higher depletable base and production relative to 2018 which only includes the additional depletion expense after closing on August, 22, 2018. The depletion rate increased following the Strategic Combination in 2018 due to the addition of proved plus probable reserves at a higher cost than our historical depletion rate.

Impairment

In 2019, we recorded impairment expense of $187.8 million on our Peace River CGU which reflects a sustained decline in heavy oil prices in Canada which resulted in a change in the development plans for our thermal projects at Peace River. We did not identify any indicators of impairment or impairment reversals on our remaining CGUs.

In 2018, we recorded total impairments of $285.3 million on our Conventional CGU and our Eagle Ford CGU. We recorded a $65.0 million impairment on our Conventional assets in Canada due to a sustained decline in natural gas prices and a reduction in planned exploration and development expenditures on these assets. We also recorded a $220.3 million impairment in our Eagle Ford CGU in 2018 as the rate of future development outlined by the operator was reduced and resulted in a decline in the net present value of our proved plus probable reserves with no significant changes to proved plus probable reserves volumes. We did not identify any indicators of impairment or impairment reversals on our remaining CGUs.

Share-Based Compensation Expense

Share-based compensation ("SBC") expense associated with the Share Award Incentive Plan is recognized in net income or loss over the vesting period of the share awards with a corresponding increase in contributed surplus. The issuance of common shares upon the conversion of share awards is recorded as an increase in shareholders' capital with a corresponding reduction in contributed surplus. 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 $15.9 million for 2019 which is lower than $19.5 million reported for 2018. SBC expense is lower in 2019 due to the lower total value of awards granted in 2019 compared to 2018 which included additional SBC expense associated with the Strategic Combination.

As a result of the Strategic Combination, Baytex became the successor to Raging River's Share Awards Plan, 2012 Option Plan and 2016 Option Plan (collectively, the "Raging River Plans"). Although no new grants will be made under the Raging River Plans, share awards and options held under the Raging River Plans in existence at August 22, 2018 were converted to share awards and options to purchase shares in Baytex.

Foreign Exchange

Unrealized foreign exchange gains and losses represent the change in value of the long-term notes and bank loan denominated in U.S. dollars. The long-term notes and bank loan 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 operations.

	Years Ended December 31		
($ thousands except for exchange rates)	**2019**	2018	Change
Unrealized foreign exchange (gain) loss	**$ (62,753)**	$ 106,143	$ (168,896)
Realized foreign exchange loss	**966**	2,151	(1,185)
Foreign exchange (gain) loss	**$ (61,787)**	$ 108,294	$ (170,081)
CAD/USD exchange rates:			
At beginning of period	**1.3646**	1.2518	
At end of period	**1.2965**	1.3646	

We recorded an unrealized foreign exchange gain of $62.8 million for 2019 due to a strengthening of the Canadian dollar relative to the U.S. dollar at December 31, 2019 compared to December 31, 2018. The Canadian dollar weakened relative to the U.S. dollar at December 31, 2018 compared to December 31, 2017 which resulted in an unrealized foreign exchange loss of $106.1 million in 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 loss of $1.0 million for 2019 compared to a loss of $2.2 million for 2018.

Income Taxes

	Years Ended December 31		
($ thousands)	**2019**	2018	Change
Current income tax expense (recovery)	**$ 2,093**	$ (35)	$ 2,128
Deferred income tax recovery	**(68,555)**	(101,732)	33,177
Total income tax recovery	**$ (66,462)**	$ (101,767)	$ 35,305

Current income expense was $2.1 million for 2019 compared to a nominal recovery recorded in 2018. The current tax expense for 2019 reflects state taxes owing on our U.S. operations.

We recorded a deferred income tax recovery of $68.6 million for 2019 compared to $101.7 million for 2018. We recorded a lower deferred income tax recovery in 2019 primarily due to the increase in adjusted funds flow relative to 2018. The deferred tax recovery for 2019 includes a $6.1 million recovery associated with the reduction in corporate tax rates in Alberta along with a $44.6 million recovery associated with the impairment of oil and gas properties. In 2018 the deferred income tax recovery included a $63.4 million recovery associated with the impairment of oil and gas properties.

In June 2016, 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.

Canadian Tax Pools *($ thousands)*	**December 31, 2019**	December 31, 2018
Canadian oil and natural gas property expenditures	**$ 492,616**	$ 529,044
Canadian development expenditures	**696,298**	765,289
Canadian exploration expenditures	**9,726**	8,875
Undepreciated capital costs	**433,768**	502,320
Non-capital losses	**705,298**	593,251
Financing costs and other	**4,424**	33,866
Total Canadian tax pools	**$ 2,342,130**	$ 2,432,645

U.S. Tax Pools *($ thousands)*		
Depletion	**$ 156,184**	$ 180,367
Intangible drilling costs	**18,618**	133,345
Tangibles	**64,496**	69,138
Non-capital losses	**1,009,260**	1,140,579
Other	**452,710**	407,654
Total U.S. tax pools	**$ 1,701,268**	$ 1,931,083

Net Income (Loss) and Adjusted Funds Flow

	Years Ended December 31		
($ thousands)	**2019**	2018	Change
Petroleum and natural gas sales	**$ 1,805,919**	$ 1,428,870	$ 377,049
Royalties	**(320,241)**	(313,754)	(6,487)
Revenue, net of royalties	**1,485,678**	1,115,116	370,562
Expenses			
Operating	**(397,716)**	(311,592)	(86,124)
Transportation	**(43,942)**	(36,869)	(7,073)
Blending and other	**(68,795)**	(68,832)	37
Operating netback	**$ 975,225**	$ 697,823	$ 277,402
General and administrative	**(45,469)**	(45,825)	356
Cash financing and interest	**(107,417)**	(104,318)	(3,099)
Realized financial derivatives gain (loss)	**75,620**	(73,165)	148,785
Realized foreign exchange (loss) gain	**(966)**	(2,151)	1,185
Other income	**7,526**	1,172	6,354
Current income tax (expense) recovery	**(2,093)**	35	(2,128)
Payments on onerous contracts	**—**	(588)	588
Adjusted funds flow	**$ 902,426**	$ 472,983	$ 429,443
Transaction costs	**—**	(13,074)	13,074
Exploration and evaluation	**(11,764)**	(21,729)	9,965
Depletion and depreciation	**(731,686)**	(558,684)	(173,002)
Share based compensation	**(15,894)**	(19,534)	3,640
Non-cash financing and accretion	**(18,448)**	(14,768)	(3,680)
Unrealized financial derivatives (loss) gain	**(82,817)**	116,715	(199,532)
Unrealized foreign exchange gain (loss)	**62,753**	(106,143)	168,896
Gain on dispositions	**2,238**	1,946	292
Impairment	**(187,822)**	(285,341)	97,519
Deferred income tax recovery	**68,555**	101,732	(33,177)
Payments on onerous contracts	**—**	588	(588)
Net income (loss) for the period	**$ (12,459)**	$ (325,309)	$ 312,850

We generated adjusted funds flow of $902.4 million for 2019, an increase of $429.4 million from adjusted funds flow of $473.0 million reported for 2018. Operating netback for 2019 was $277.4 million higher than 2018 due to increased production along with improved oil price realizations in Canada due to tighter differentials and a decrease in our average royalty rate as a result of the Strategic Combination. We recorded realized gains on financial derivatives of $75.6 million in 2019 compared to realized losses of

$73.2 million in 2018 which also contributed to the $429.4 million increase in adjusted funds flow. The $429.4 million increase in adjusted funds flow contributed to the $312.9 million decrease in our net loss to $12.5 million for 2019 compared to a net loss of $325.3 million in 2018. In 2019, we recorded impairments of $187.8 million due to a sustained decline in Canadian heavy oil prices which resulted in a change in development plans for our thermal projects at Peace River compared to total impairments of $285.3 million in 2018 related to our Conventional and Eagle Ford assets.

Other Comprehensive Income (Loss)

Other comprehensive income or loss is comprised of the foreign currency translation adjustment on U.S. net assets not recognized in income or loss. The $111.7 million foreign currency translation loss for 2019 relates to the change in value of our U.S. net assets expressed in Canadian dollars and is due to the strengthening of the Canadian dollar against the U.S. dollar. The CAD/USD exchange rate was 1.2965 as at December 31, 2019 compared to 1.3646 as at December 31, 2018.

Capital Expenditures

	Years Ended December 31					
	2019			2018		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 319,417**	**$ 166,094**	**$ 485,511**	$ 225,904	$ 178,665	$ 404,569
Facilities	**41,141**	**10,220**	**51,361**	58,813	14,605	73,418
Land, seismic and other	**13,805**	**1,614**	**15,419**	17,400	334	17,734
Total exploration and development	**$ 374,363**	**$ 177,928**	**$ 552,291**	$ 302,117	$ 193,604	$ 495,721
Acquisitions, net of proceeds from divestitures	**$ 2,180**	**$ —**	**$ 2,180**	$ (1,818)	$ —	$ (1,818)
Strategic Combination [1]	**$ —**	**$ —**	**$ —**	$ 1,605,668	$ —	$ 1,605,668

(1) Includes $1,239.0 million of consideration associated with 315.3 million common shares issued by Baytex at a closing share price of $3.93 per common share along with $3.1 million of share based compensation and assumed net debt of $363.6 million.

Exploration and development expenditures were $552.3 million for 2019 compared to $495.7 million for 2018. Higher exploration and development expenditures in 2019 relative to 2018 reflects the additional activity associated with our Viking and Duvernay light oil properties which were acquired during Q3/2018 as part of the Strategic Combination.

In Canada, we invested $374.4 million on exploration and development activities in 2019 which is $72.2 million higher than $302.1 million in 2018. Exploration and development activity in 2019 includes costs associated with drilling 279 (247.8 net) light oil wells, 42 (42.0 net) heavy oil wells, 4 (4.0 net) stratigraphic exploration wells along with $13.8 million of associated facility expenditures. Total exploration and development costs were higher in 2019 as 2018 only includes exploration and development activity on our Viking and Duvernay properties after closing of the Strategic Combination in August 2018. Exploration and development activity in 2018 includes costs associated with drilling 125 (87.0 net) light oil wells, 99 (74.9 net) heavy oil wells, 9 (9.0 net) stratigraphic wells along with $17.4 million of associated facility expenditures.

Total U.S. exploration and development expenditures were $177.9 million for 2019 which is $15.7 million lower than $193.6 million for 2018. The decrease in exploration and development expenditures in 2019 relative to 2018 reflects slightly lower drilling and completion activity along with a reduction in facility expenditures required to support current production levels on our Eagle Ford properties. During 2019 we participated in drilling 96 (20.2 net) wells and commenced production from 109 (25.1 net) wells compared to 91 (20.8 net) wells drilled and 120 (26.2 net) wells on production during 2018.

We completed minor acquisition and disposition activity in 2019 for net consideration of $2.2 million compared to net proceeds of $1.8 million in 2018.

CAPITAL RESOURCES AND LIQUIDITY

Our capital management objective is to maintain 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 December 31, 2019, our capital structure was comprised of shareholders' capital, long-term notes, working capital and our bank loan.

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 sustain our operations and 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.

Management of debt is a priority for Baytex in order to sustain operations and support our plans to deliver shareholder value. At December 31, 2019, net debt of $1,871.8 million was $393.4 million lower than $2,265.2 million at December 31, 2018. The decrease in net debt is primarily a result of debt repayment from the free cash flow of $328.8 million generated in 2019. Net debt was also lower at December 31, 2019 due to a strengthening of the Canadian dollar which resulted in a $62.8 million decrease in the reported principal amount of our U.S. dollar denominated net debt relative to December 31, 2018.

We monitor our capital structure and liquidity requirements using a net debt to adjusted funds flow ratio on a twelve month trailing basis. At December 31, 2019, our net debt to adjusted funds flow ratio was 2.1 compared to a ratio of 3.1 as at December 31, 2018. The decrease in the net debt to adjusted funds flow ratio relative to December 31, 2018 is attributed to higher adjusted funds flow combined with a $393.4 million decrease in net debt at December 31, 2019.

Bank Loan

At December 31, 2019, the principal amount of bank loan and letters of credit outstanding was $521.7 million and we had approximately $523.8 million of undrawn capacity under our credit facilities that total approximately $1,045.5 million. Our facilities include US$575 of revolving credit facilities (the "Revolving Facilities") and a CAD$300 million non-revolving term loan (the "Term Loan").

On March 3, 2020, we amended our credit facilities to extend the maturities of the Revolving Facilities and the Term Loan to April 2, 2024. The maturity of the credit facilities will automatically extend 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 at 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. 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 exceeds 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 for 2019 was 4.0% as compared to 4.3% for 2018.

Financial Covenants

The following table summarizes the financial covenants applicable to the credit facilities and Baytex's compliance therewith as at December 31, 2019.

Covenant Description	Position as at December 31, 2019	Covenant
Senior Secured Debt(1) to Bank EBITDA(2) (Maximum Ratio)	**0.52:1.00**	3.50:1.00
Interest Coverage(3) (Minimum Ratio)	**9.42:1.00**	2.00:1.00

(1) "Senior Secured Debt" is defined as the principal amount of the bank loan and other secured obligations identified in the credit agreement. As at December 31, 2019, the Company's Senior Secured Debt totaled $521.7 million which includes $506.5 million of principal amounts outstanding and $15.2 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, 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 December 31, 2019 was $1,011.9 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 expenses, excluding accretion of debt issue costs and asset retirement obligations, for the twelve months ended December 31, 2019 were $107.4 million.

Long-Term Notes

At December 31, 2019 we had three series of long-term notes outstanding that total $1,337.2 million. The long-term notes do not contain any significant financial maintenance covenants. The long-term notes contain a debt incurrence covenant that restricts our 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 above) to financing and interest expense on a trailing twelve month basis) of 2.50:1.00. As at December 31, 2019, the fixed charge coverage ratio was 8.04:1.00.

On February 5, 2020, we issued US$500 million of senior unsecured notes bearing interest at 8.75% payable semi-annually which mature on April 1, 2027 (the "8.75% Senior Notes"). These 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 $12.4 million were incurred in conjunction with the issuance which resulted in net proceeds of $652.3 million.

On February 20, 2020, we used a portion of the net proceeds from the issuance of the 8.75% Senior Notes to redeem our US$400 million principal amount of our 5.125% senior unsecured notes due June 1, 2021 at par plus accrued interest. We also issued a redemption notice for the $300 million principal amount of our 6.625% senior unsecured notes due July 19, 2022 for early redemption on March 6, 2020 at 101.104% of the principal amount plus accrued interest.

On September 13, 2019, we completed the early redemption of the US$150 million ($198.1 million) principal amount of 6.75% senior unsecured notes, due February 17, 2011.

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") and US$400 million of 5.625% notes due June 1, 2024 (the "5.625% Notes"). The 5.125% Notes and the 5.625% Notes pay interest semi-annually with the principal amount repayable at maturity. On February 20, 2020, we completed the early redemption of the US$400 million principal amount of 5.125% Notes at par plus accrued interest. 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.

Shareholders' Capital

We are authorized to issue an unlimited number of common shares and 10.0 million preferred shares. The rights and terms of the preferred shares are determined upon issuance. During the year ended December 31, 2019, we issued 4.2 million common shares pursuant to our share-based compensation program. As at March 3, 2020, we had 560.5 million common shares issued and outstanding and no preferred shares issued and outstanding.

Contractual Obligations

Baytex has a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact the Company's cash flow from operations in an ongoing manner. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of December 31, 2019 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	**$ 207,454**	$ 207,454	$ —	$ —	$ —
Bank loan[(1) (2)]	**506,471**	—	506,471	—	—
Long-term notes[(2)]	**1,337,200**	—	818,600	518,600	—
Interest on long-term notes[(3)]	**217,247**	75,625	100,303	41,319	—
Lease obligations	**14,568**	6,216	7,748	604	—
Processing agreements	**39,352**	10,234	10,591	8,848	9,679
Transportation agreements	**115,999**	11,636	41,263	37,099	26,001
Total	**$ 2,438,291**	$ 311,165	$ 1,484,976	$ 606,470	$ 35,680

(1) At December 31, 2019, the bank loan was set to mature on April 2, 2021. On March 3, 2020, we amended the bank loan to extend maturity to April 2, 2024 which 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.

(2) Principal amount of instruments. On February 5, 2020, we issued US$500 million principal amount of 8.75% senior unsecured notes due 2027 and issued a redemption notice for the $300 million principal amount of 6.625% senior unsecured notes due 2022. We expect to complete the redemption of these notes on March 6, 2020. On February 20, 2020 we completed the redemption of the US$400 million principal amount of senior unsecured notes due 2021.

(3) Excludes interest on bank loan as interest payments on bank loans fluctuate based on interest rate and bank loan balance.

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.

FOURTH QUARTER 2019 OPERATING AND FINANCIAL RESULTS

	Three Months Ended December 31					
	2019			2018		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total daily production						
Light oil and condensate (bbl/d)	**21,531**	**22,375**	**43,906**	23,978	21,009	44,987
Heavy oil (bbl/d)	**27,050**	**—**	**27,050**	26,339	—	26,339
NGL (bbl/d)	**1,170**	**7,529**	**8,699**	1,189	9,138	10,327
Total liquids (bbl/d)	**49,751**	**29,904**	**79,655**	51,506	30,147	81,653
Natural gas (mcf/d)	**48,260**	**51,975**	**100,235**	53,682	49,742	103,424
Total production (boe/d)	**57,794**	**38,566**	**96,360**	60,453	38,437	98,890
Operating netback ($/boe)						
Light oil and condensate ($/bbl)	**$ 65.31**	**$ 76.46**	**$ 71.00**	$ 40.55	$ 83.28	$ 60.50
Heavy oil ($/bbl) (1)	**40.32**	**—**	**40.32**	13.65	—	13.65
NGL ($/bbl)	**16.22**	**18.75**	**18.41**	26.84	30.37	29.96
Natural gas ($/mcf)	**2.39**	**3.20**	**2.81**	1.67	5.35	3.44
Total sales, net of blending and other per boe	**45.52**	**52.33**	**48.25**	24.04	59.66	37.89
Royalties per boe	**(4.73)**	**(14.69)**	**(8.72)**	(3.10)	(17.68)	(8.77)
Operating expense per boe	**(14.41)**	**(6.47)**	**(11.23)**	(13.42)	(6.56)	(10.76)
Transportation expense per boe	**(1.66)**	**—**	**(1.00)**	(1.98)	—	(1.21)
Operating netback per boe	**$ 24.72**	**$ 31.17**	**$ 27.30**	$ 5.54	$ 35.42	$ 17.15
Financial						
Petroleum and natural gas sales	**$ 260,217**	**$ 185,678**	**$ 445,895**	$ 147,472	$ 210,965	$ 358,437
Royalties	**(25,154)**	**(52,128)**	**(77,282)**	(17,229)	(62,536)	(79,765)
Revenue, net of royalties	**235,063**	**133,550**	**368,613**	130,243	148,429	278,672
Operating expense	**(76,623)**	**(22,950)**	**(99,573)**	(74,663)	(23,194)	(97,857)
Transportation expense	**(8,840)**	**—**	**(8,840)**	(10,994)	—	(10,994)
Blending and other expense	**(18,167)**	**—**	**(18,167)**	(13,755)	—	(13,755)
Operating netback	**$ 131,433**	**$ 110,600**	**$ 242,033**	$ 30,831	$ 125,235	$ 156,066
Realized financial derivatives (loss) gain	**—**	**—**	**22,956**	—	—	(3,063)
General and administrative	**—**	**—**	**(9,893)**	—	—	(14,096)
Cash interest	**—**	**—**	**(24,389)**	—	—	(27,933)
Other	**—**	**—**	**1,440**	—	—	(146)
Adjusted funds flow	**$ 131,433**	**$ 110,600**	**$ 232,147**	$ 30,831	$ 125,235	$ 110,828
Net income (loss)	**$ (134,348)**	**$ 44,937**	**$ (117,772)**	$ (122,645)	$ (133,752)	$ (231,238)
Exploration and development expenditures	**$ 104,460**	**$ 48,657**	**$ 153,117**	$ 125,507	$ 58,655	$ 184,162
Acquisitions, net of proceeds from divestitures	**$ 563**	**$ —**	**$ 563**	$ 183	$ —	$ 183
Net debt			**$1,871,791**			$2,265,167

	Three Months Ended December 31		
	2019	2018	Change
Benchmark Averages			
WTI oil (US$/bbl)(1)	**56.96**	58.81	(1.85)
LLS oil (US$/bbl)(2)	**60.73**	66.64	(5.91)
LLS oil differential to WTI (US$/bbl)	**3.77**	7.83	(4.06)
Edmonton par oil ($/bbl)	**68.10**	42.68	25.42
Edmonton par oil differential to WTI (US$/bbl)	**(5.37)**	(26.51)	21.14
WCS heavy oil ($/bbl)(3)	**54.29**	25.62	28.67
WCS heavy oil differential to WTI (US$/bbl)	**(15.83)**	(39.42)	23.59
AECO natural gas price ($/mcf)(4)	**2.34**	1.94	0.40
NYMEX natural gas price (US$/mmbtu)(5)	**2.50**	3.64	(1.14)
CAD/USD average exchange rate	**1.3201**	1.3215	(0.0014)

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.
(2) LLS refers to the Argus trade month average for Louisiana Light Sweet oil.
(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.

We delivered strong operating and financial results in Q4/2019. We invested $153.1 million on exploration and development expenditures in Q4/2019 and generated adjusted funds flow of $232.1 million. Production of 96,360 boe/d for Q4/2019 was consistent with expectations and contributed to annual production for 2019 that exceeded our annual guidance of approximately 97,000 boe/d. Free cash flow of $72.9 million in Q4/2019 was used for debt reduction and contributed to a $99.5 million reduction in net debt relative to Q3/2019.

In Canada, production averaged 57,794 boe/d in Q4/2019 which is 2,659 boe/d lower than 60,453 boe/d reported for Q4/2018. The decrease in production reflects lower exploration and development activity in the second half of 2019 relative to the same period of 2018. Our weighted average realized price of $45.52/boe for Q4/2019 was $21.48/boe higher than $24.04/boe for Q4/2018 which was impacted by a significant widening of light and heavy oil differentials. In Q4/2019, the Edmonton Par benchmark price traded at a US$5.37/bbl discount to WTI while the WCS differential was a US$15.83/bbl discount to WTI compared to Q4/2018 when Edmonton par traded at a US$26.51/bbl discount to WTI and the WCS heavy oil differential was US$39.42/bbl. Operating netback of $131.4 million ($24.72/boe) for Q4/2019 is $100.6 million ($19.18/boe) higher than $30.8 million ($5.54/boe) reported for the same period of 2018. Exploration and development expenditures of $104.5 million in Q4/2019 includes drilling and completion costs associated with 73 (70.7 net) wells compared to 98 (71.5 net) wells in Q4/2018.

In the U.S., production of 38,566 boe/d for Q4/2019 was consistent with 38,437 boe/d reported for Q4/2018. Our realized price of $52.33/boe was $7.33/boe lower than our realized price of $59.66/boe in Q4/2018 as a result of the decline in U.S. crude oil pricing. The LLS benchmark averaged US$60.73/bbl in Q4/2019 which is US$5.91/boe lower than US$66.64/bbl during Q4/2018. Operating netback of $110.6 million ($31.17/boe) was $14.6 million ($4.24/boe) lower than $125.2 million ($35.41/boe) for Q4/2018 primarily due to lower benchmark prices and lower realized pricing in Q4/2019. Exploration and development expenditures of $48.7 million in Q4/2019 includes costs associated with drilling 27 (6.3 net) wells and commencing production from 24 (6.5 net) wells. Exploration and development expenditures were lower in Q4/2019 due to the timing of drilling and completion activity relative to Q4/2018 when we drilled 19 (3.3 net) wells and brought 31 (5.9 net) wells on production.

We generated adjusted funds flow of $232.1 million in Q4/2019 which is $121.3 million higher than $110.8 million in Q4/2018. The increase was driven by stronger realized pricing in Canada and resulted in operating netback of $27.30/boe in Q4/2019 which is $10.15/boe higher relative to $17.15/boe in Q4/2018. Production of 96,360 boe/d in Q4/2019 compared to 98,890 boe/d for Q4/2018 reflects lower exploration and development activity in the second half of relative to the same period of 2018. The increase in our realized price more than offset the impact of lower production and resulted in an $86.0 million increase in operating netback in Q4/2019 compared to Q4/2018. Lower G&A expense and cash interest expense combined with realized gains on financial derivatives also contributed to the increase in adjusted funds flow in Q4/2019 relative to the same period of 2018. G&A expense of $9.9 million in Q4/2019 was lower than $14.1 million in Q4/2018 which reflects the efficiencies we were able to realize as a result of the Strategic Combination. Interest expense of $24.4 million in Q4/2019 was $3.5 million lower than $27.9 million for Q4/2018 due the reduction in net debt including the early redemption of the US$150 million senior unsecured notes in September 2019 which resulted in lower interest on our long-term notes. We recorded hedging gains of $23.0 million in Q4/2019 compared to hedging losses of $3.1 million in Q4/2018.

We recorded a net loss of $117.8 million in Q4/2019 compared to net loss of $231.2 million in Q4/2018. The decrease in the net loss for Q4/2019 was primarily a result of the increase in adjusted funds flow which was $110.8 million higher than Q4/2018 due to narrower Canadian oil differentials and stronger realized pricing in Canada. The net loss for Q4/2019 includes a $187.8 million impairment expense recorded in Q4/2019 due to the sustained decline in Canadian heavy oil prices which resulted in a change in development plans for our thermal projects in Peace River. The net loss for Q4/2018 includes a $285.3 million impairment expense recorded in Q4/2018 due to a change in development plans for our Conventional and Eagle Ford properties. The impact of higher adjusted funds flow and lower impairment expense in Q4/2019 were offset by a loss of $27.5 million associated with unrealized changes in the carrying value of our financial derivatives and our U.S. denominated debt compared to a gain of $113.8 million in Q4/2018.

QUARTERLY FINANCIAL INFORMATION

	2019				2018			
($ thousands, except per common share amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Petroleum and natural gas sales	**445,895**	424,600	482,000	453,424	358,437	436,761	347,605	286,067
Net income (loss)	**(117,772)**	15,151	78,826	11,336	(231,238)	27,412	(58,761)	(62,722)
Per common share - basic	**(0.21)**	0.03	0.14	0.02	(0.42)	0.07	(0.25)	(0.27)
Per common share - diluted	**(0.21)**	0.03	0.14	0.02	(0.42)	0.07	(0.25)	(0.27)
Adjusted funds flow	**232,147**	213,379	236,130	220,770	110,828	171,210	106,690	84,255
Per common share - basic	**0.42**	0.38	0.42	0.40	0.20	0.46	0.45	0.36
Per common share - diluted	**0.42**	0.38	0.42	0.40	0.20	0.45	0.45	0.36
Exploration and development	**153,117**	139,085	106,246	153,843	184,162	139,195	78,830	93,534
Canada	**104,460**	96,774	68,259	104,870	125,507	94,477	30,608	51,525
U.S.	**48,657**	42,311	37,987	48,973	58,655	44,718	48,222	42,009
Acquisitions, net of divestitures	**563**	(30)	1,647	—	229	—	(21)	(2,026)
Net debt	**1,871,791**	1,971,339	2,028,686	2,175,241	2,265,167	2,112,090	1,784,835	1,783,379
Total assets	**5,914,083**	6,233,875	6,222,190	6,359,157	6,377,198	6,491,303	4,476,906	4,433,074
Common shares outstanding	**558,305**	557,972	556,798	555,872	554,060	553,950	236,662	236,578
Daily production								
Total production (boe/d)	**96,360**	94,927	98,402	101,115	98,890	82,412	70,664	69,522
Canada (boe/d)	**57,794**	58,134	58,580	60,018	60,453	45,214	34,042	33,505
U.S. (boe/d)	**38,566**	36,793	39,822	41,097	38,437	37,198	36,622	36,017
Benchmark prices								
WTI oil (US$/bbl)	**56.96**	56.45	59.81	54.90	58.81	69.50	67.88	62.87
WCS heavy (US$/bbl)	**41.13**	44.21	49.14	42.61	19.39	47.25	48.61	38.59
CAD/USD avg exchange rate	**1.3201**	1.3207	1.3376	1.3293	1.3215	1.3070	1.2911	1.2651
AECO gas ($/mcf)	**2.34**	1.04	1.17	1.94	1.94	1.35	1.03	1.85
NYMEX gas (US$/mmbtu)	**2.50**	2.23	2.64	3.15	3.64	2.90	2.80	3.00
Sales price ($/boe) (1)	**48.25**	47.14	51.49	47.98	37.89	55.03	51.22	42.96
Royalties ($/boe)	**(8.72)**	(8.59)	(9.67)	(8.94)	(8.77)	(12.13)	(12.01)	(10.36)
Operating expense ($/boe)	**(11.23)**	(11.15)	(11.22)	(11.02)	(10.76)	(10.25)	(10.91)	(10.53)
Transportation expense ($/boe)	**(1.00)**	(1.13)	(1.33)	(1.46)	(1.21)	(1.26)	(1.22)	(1.36)
Operating netback ($/boe)	**27.30**	26.27	29.27	26.56	17.15	31.39	27.08	20.71
Realized financial derivatives gain (loss) ($/boe)	**2.59**	2.39	1.45	2.07	(0.34)	(4.07)	(4.57)	(1.57)
Operating netback after financial derivatives ($/boe)	**29.89**	28.66	30.72	28.63	16.81	27.32	22.51	19.14

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

In Q4/2019 we delivered our fifth consecutive quarter of strong operating and financial results following closing of the Strategic Combination in Q3/2018. Production has increased from 69,522 boe/d during Q1/2018 to a high of 101,115 boe/d during Q1/2019 as a result of the Strategic Combination along with our successful development programs in the U.S. and Canada. As planned, production was lower in Q3/2019 and began to increase in Q4/2019 as a result of the timing of our exploration and development activity during 2019. Improved well productivity from enhanced completion techniques resulted in relatively consistent average daily production in the U.S. despite lower quarterly exploration and development expenditures. In Canada, our exploration and development program was focused on our heavy oil properties at Peace River and Lloydminster. Exploration and development activity in Canada increased following the Strategic Combination with the addition of our Viking and Duvernay light oil properties.

Global benchmark prices for crude oil have fluctuated over the last eight quarters as attempts to balance the market with production cuts have been mitigated by increasing production in North America and concerns over global demand. Our realized pricing in Canada improved in 2019 after a narrowing of light and heavy oil differentials along with a higher weighting of light oil production following the Strategic Combination. The WCS benchmark averaged US$41.13/bbl in Q4/2019 compared to US$19.39/bbl in Q4/2018.

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 began to improve in 2018 as commodity prices strengthened and continued to improve through Q3/2019 following the Strategic Combination. Increased production and strong price realizations due to a higher proportion of light oil production resulted in adjusted funds flow of $232.1 million in Q4/2019 compared to $84.3 million in Q1/2018.

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. We generated free cash flow of $328.8 million in 2019 which was directed towards debt repayment and resulted in net debt of $1,871.8 million at Q4/2019 which is only $88.4 million higher than $1,783.4 million at Q1/2018 despite the additional $363.6 million of net debt assumed in conjunction with the Strategic Combination.

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at December 31, 2019, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets, liabilities, revenues and expenses. These judgments, estimates and assumptions are based on all relevant information available to the Company at the time of financial statement preparation. Actual results can differ from those estimates as the effect of future events cannot be determined with certainty. The key areas of judgment or estimation uncertainty that have a significant risk of causing material adjustment to the reported amounts of assets, liabilities, revenues, and expenses are discussed below.

Reserves

The Company uses estimates of oil, natural gas and natural gas liquids ("NGL") reserves in the calculation of depletion and in the determination of fair value estimates for non-financial assets. The process to estimate reserves is complex and requires significant judgment. Estimates of the Company's reserves are evaluated annually by independent reserves evaluators and represent the estimated recoverable quantities of oil, natural gas and NGL and the related net cash flows. This evaluation of reserves is prepared in accordance with the reserves definition contained in National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" and the Canadian Oil and Gas Evaluation Handbook.

Estimates of economically recoverable oil, natural gas and NGL and their future net cash flows are based on a number of factors and assumptions. Changes to estimates and assumptions such as forward price forecasts, production rates, ultimate reserve recovery, timing and amount of capital expenditures, production costs, marketability of oil and natural gas, royalty rates and other geological, economic and technical factors could have a significant impact on reported reserves. Changes in the Company's reserves estimates can have a significant impact on the carrying values of the Company's oil and gas properties, the calculation of depletion, the timing of cash flows for asset retirement obligations, asset impairments and estimates of fair value determined in accounting for business combinations.

Cash-generating Units ("CGUs")

The Company's oil and gas properties are aggregated into CGUs which are the smallest identifiable group of assets that generates cash flows that are largely independent of the cash flows from other assets or groups of assets. The aggregation of assets in CGUs requires management judgment and is based on geographical proximity, shared infrastructure and similar exposure to market risk.

Identification of Impairment and Impairment Reversal Indicators

Judgment is required to assess when indicators of impairment or impairment reversal exist and when a calculation of the recoverable amount is required. The CGUs comprising oil and gas properties are reviewed at each reporting date to assess whether there is any indication of impairment or impairment reversal. The assessment for each CGU considers significant changes in reservoir performance including forecasted production volumes, forecasted royalty, operating, capital and abandonment and reclamation costs, forecasted oil and gas prices and the resulting cash flows from proved plus probable oil and gas reserves.

Measurement of Recoverable Amount

If indicators of impairment or impairment reversal are determined to exist, the recoverable amount of an asset or CGU is calculated based on the higher of value-in-use ("VIU") and fair value less cost of disposal ("FVLCD"). These calculations require the use of estimates and assumptions including cash flows associated with proved plus probable oil and gas reserves, the discount rate used to present value future cash flows and assumptions regarding the timing and amount of capital expenditures and future abandonment and reclamation obligations. Any changes to these estimates and assumptions could impact the calculation of the recoverable amount and the carrying value of assets.

Exploration and Evaluation ("E&E") Assets

Costs associated with acquiring oil and natural gas licenses and exploratory drilling are accumulated as E&E assets pending determination of technical feasibility and commercial viability. The determination of technical feasibility and commercial viability of E&E assets for the purposes of reclassifying such assets to oil and gas properties is subject to management judgment. Management uses the establishment of commercial reserves as the basis for determining technical feasibility and commercial viability. Upon determination of commercial reserves, E&E assets are tested for impairment and reclassified to oil and natural gas properties.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting when the assets acquired meet the definition of a business in accordance with IFRS.

Determination of the acquirer in a business combination requires management judgment. In determining the acquirer in a business combination, factors such as voting rights of all equity instruments, the intended corporate governance structure, composition of senior management of the combined company, and various metrics used to evaluate the relative size of each company are considered.

The determination of fair value assigned to assets acquired and liabilities assumed requires management to make assumptions and estimates including forecast benchmark commodity prices, estimates of reserves acquired and discount rates used to present value future cash flows. Changes in any of the assumptions or estimates used in determining the fair value of assets acquired and liabilities assumed could impact the amounts assigned to assets, liabilities and goodwill.

Financial Derivatives

Financial derivatives are measured at fair value on each reporting date. The Company uses quoted commodity prices, estimates of future volatility prices and interest rates available at period end to determine the fair value of outstanding financial derivatives. Changes in market pricing between period end and settlement of the derivative contracts could have a significant impact on financial results related to the financial derivatives.

Asset Retirement Obligations

The Company's provision for asset retirement obligations is based on estimated costs to abandon and reclaim the wells and the facilities, the estimated time period during which these costs will be incurred in the future, and discount and inflation rates. The provision for asset retirement obligations represents management's best estimate of the present value of the future abandonment and reclamation costs required under current regulatory requirements. Actual abandonment and reclamation costs could be materially different from estimated amounts.

Income Taxes

Regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. Interpretation and application of existing regulation and legislation requires management judgment. Income tax filings are subject to audit and re-assessment and changes in facts, circumstances and interpretations of the standards may result in a material change to the Company's provision for income taxes. Estimates of future income taxes are subject to measurement uncertainty.

CURRENT AND FUTURE CHANGES IN ACCOUNTING POLICIES

Changes in significant accounting policies

Leases

Baytex adopted IFRS 16 *Leases* on January 1, 2019, using the modified retrospective approach. The modified retrospective approach does not require restatement of comparative financial information as it recognizes the cumulative effect on transition as an adjustment to opening retained earnings and applies the standard prospectively. Comparative information in the Company's consolidated statements of financial position, consolidated statements of loss and comprehensive loss, consolidated statements of changes in equity, and consolidated statements of cash flows has not been restated and continues to be accounted for in accordance with the Company's previous accounting policy found in the 2018 annual financial statements.

The cumulative effect of initial application of the standard was to recognize an $18.0 million increase to right-of-use assets ("lease assets"), a $2.0 million reduction of onerous contracts and a $18.0 million increase to lease obligations. Initial measurement of the lease obligation was determined based on the remaining lease payments at January 1, 2019 using a weighted averaged incremental borrowing rate of approximately 3.9%. The lease assets were initially recognized at an amount equal to the lease obligations. The lease assets and lease obligations recognized largely relate to the Company's head office lease in Calgary.

The adoption of IFRS 16 using the modified retrospective approach allowed the Company to use the following practical expedients in determining the opening transition adjustment:

- The weighted average incremental borrowing rate in effect at January 1, 2019 was used as opposed to the rate in effect at inception of the lease;
- Leases with a remaining term of less than 12 months as at January 1, 2019 were accounted for as short-term leases;
- Leases with an underlying asset of low value are recorded as an expense and not recognized as a lease asset;
- Leases with similar characteristics were accounted for as a portfolio using a single discount rate; and
- Used the Company's previous assessment under IAS 37, "Provisions, Contingent Liabilities and Contingent Assets' for onerous contracts instead of reassessing the lease assets for impairment at January 1, 2019.

The Company's accounting policy for leases effective January 1, 2019 is set forth below. The Company applied IFRS 16 using the modified retrospective approach. Comparative information continues to be accounted for in accordance with the Company's previous accounting policy found in the 2018 annual financial statements.

Leases

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. A lease obligation and corresponding right-of-use asset ("lease asset") are recognized at the commencement of the lease. The present value of the lease obligation is based on the future lease payments and is discounted using the Company's incremental borrowing rate when the rate implicit in the lease is not readily available. The Company uses a single discount rate for a portfolio of leases with similar characteristics. The lease asset is recognized at the amount of the lease obligation, adjusted for lease incentives received and initial direct costs, on commencement of the lease. Depreciation is recognized on the lease asset over the shorter of the estimated useful life of the asset or the lease term.

Lease payments are allocated between the liability and interest expense. Interest expense is recognized on the lease obligations using the effective interest rate method and payments are applied against the lease obligation.

Management judgement is required to determine the discount rate used to calculate the present value of the lease obligation. The carrying amounts of the lease assets, lease obligations, and the resulting interest and depletion and depreciation expense are based on the implicit interest rate within the lease arrangement or, if this information is unavailable, the incremental borrowing rate. Incremental borrowing rates are based on judgments including economic environment, term, and the underlying risk inherent to the asset.

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. Transaction costs associated with the Strategic Combination are excluded from adjusted funds flow as we consider the costs non-recurring and not reflective of our ability to generate adjusted funds flow on an ongoing 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.

	Years Ended December 31	
($ thousands)	**2019**	2018
Cash flow from operating activities	**$ 834,939**	$ 485,322
Change in non-cash working capital	**52,070**	(39,448)
Asset retirement obligations settled	**15,417**	14,035
Transaction costs	**—**	13,074
Adjusted funds flow	**$ 902,426**	$ 472,983

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 is 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.

	Years Ended December 31	
($ thousands)	**2019**	2018
Cash flow used in investing activities	**$ 617,508**	$ 463,272
Change in non-cash working capital	**(62,485)**	32,435
Proceeds from dispositions	**1,487**	2,519
Property acquisitions	**(3,667)**	(701)
Additions to other plant and equipment	**(552)**	(1,804)
Exploration and development expenditures	**$ 552,291**	$ 495,721

Free cash flow

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. We use free cash flow to evaluate funds available for debt repayment, common share repurchases, potential future dividends and acquisition and disposition opportunities.

The following table provides our computation of free cash flow.

	Years Ended December 31	
($ thousands)	**2019**	2018
Adjusted funds flow	**$ 902,426**	$ 472,983
Exploration and development expenditures	**(552,291)**	(495,721)
Payments on lease obligations	**(5,956)**	—
Asset retirement obligations settled	**(15,417)**	(14,035)
Free cash flow	**$ 328,762**	$ (36,773)

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 bank loan and long-term notes outstanding, including working capital. The current portion of financial derivatives is excluded as the valuation of the underlying contracts is subject to a high degree of volatility prior to the ultimate settlement. Onerous contracts are excluded from net debt as the underlying contracts do not represent an available source of liquidity. We use the principal amounts of the bank loan 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 bank loan 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 liquidity or repayment obligation.

The following table summarizes our calculation of net debt.

($ thousands)	**December 31, 2019**	December 31, 2018
Bank loan[1]	**$ 506,471**	$ 522,294
Long-term notes[1]	**1,337,200**	1,596,323
Trade and other payables	**207,454**	258,114
Cash	**(5,572)**	—
Trade and other receivables	**(173,762)**	(111,564)
Net debt	**$ 1,871,791**	$ 2,265,167

(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.

	Years Ended December 31	
($ thousands)	**2019**	2018
Petroleum and natural gas sales	**$ 1,805,919**	$ 1,428,870
Blending and other expense	**(68,795)**	(68,832)
Total sales, net of blending and other expense	**1,737,124**	1,360,038
Royalties	**(320,241)**	(313,754)
Operating expense	**(397,716)**	(311,592)
Transportation expense	**(43,942)**	(36,869)
Operating netback	**975,225**	697,823
Realized financial derivative (loss) gain	**75,620**	(73,165)
Operating netback after realized financial derivatives	**$ 1,050,845**	$ 624,658

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.

	Years Ended December 31	
($ thousands)	**2019**	2018
Net income (loss)	**$ (12,459)**	$ (325,309)
Plus:		
Financing and interest	**125,865**	119,086
Unrealized foreign exchange loss (gain)	**(62,753)**	106,143
Unrealized financial derivatives loss (gain)	**82,817**	(116,715)
Current income tax recovery	**2,093**	(35)
Deferred income tax recovery	**(68,555)**	(101,732)
Depletion and depreciation	**731,686**	558,684
Impairment	**187,822**	285,341
Gain on dispositions	**(2,238)**	(1,946)
Transaction costs	**—**	13,074
Non-cash items(1)	**27,658**	41,263
Adjustment for Strategic Combination (2)	**—**	255,800
Bank EBITDA	**$ 1,011,936**	$ 833,654

(1) Non-cash items include share-based compensation, exploration and evaluation expense and non-cash other expense.
(2) In accordance with the credit facilities agreements, the calculation of Bank EBITDA is adjusted to reflect the impact of material acquisitions as if the transaction had occurred on the first day of the relevant period.

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As of December 31, 2019, an evaluation was conducted of the effectiveness of our “disclosure controls and procedures” (as defined in the United States by Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the “Exchange Act”) and in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109")) under the supervision of and with the participation of management, including the President and Chief Executive Officer and the Executive Vice President and Chief Financial Officer of Baytex (collectively the "certifying officers"). Based on that evaluation, the certifying officers concluded that our disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that we file or submit under the Exchange Act or under Canadian securities legislation is (i) recorded, processed, summarized and reported within the time periods specified in the applicable rules and forms and (ii) accumulated and communicated to our management, including the certifying officers, to allow timely decisions regarding the required disclosure.

It should be noted that while the certifying officers believe that our disclosure control and procedures provide a reasonable level of assurance that they are effective, they do not expect that our disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute assurance that the objectives of the control system are met.

Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over the Company's financial reporting. Internal control over our financial reporting is a process designed under the supervision of and with the participation of management, including the certifying officers, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

Management has assessed the effectiveness of our "internal control over financial reporting" as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act and as defined by NI 52-109. The assessment was based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that our internal control over financial reporting was effective as of December 31, 2019.

The effectiveness of our internal control over financial reporting as of December 31, 2019 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their Report of Independent Registered Public Accounting Firm.

Changes in Internal Control over Financial Reporting

No changes were made to our internal control over financial reporting during the year ended December 31, 2019 that have materially affected, or are reasonably likely to materially affect, the internal controls over financial reporting except for the matters described below.

Baytex previously excluded business processes acquired through the Strategic Combination on August 22, 2018, from the Company's evaluation of internal control over financial reporting as permitted by applicable securities laws in Canada and the U.S. We completed the evaluation and integration of internal controls over financial reporting of Raging River during the third quarter of 2019.

SELECTED ANNUAL INFORMATION

The following table summarizes key annual financial and operating information over the three most recently completed financial years.

($ thousands, except per common share amounts)		**2019**		2018		2017
Revenues, net of royalties	**$**	**1,485,678**	$	1,115,116	$	857,975
Adjusted funds flow	**$**	**902,426**	$	472,983	$	347,641
Per common share - basic	**$**	**1.62**	$	1.35	$	1.48
Per common share - diluted	**$**	**1.62**	$	1.35	$	1.47
Net income (loss)	**$**	**(12,459)**	$	(325,309)	$	87,174
Per common share - basic	**$**	**(0.02)**	$	(0.93)	$	0.37
Per common share - diluted	**$**	**(0.02)**	$	(0.93)	$	0.37
Total assets	**$**	**5,914,083**	$	6,377,198	$	4,372,111
Bank loan - principal	**$**	**506,471**	$	522,294	$	213,376
Long term notes - principal	**$**	**1,337,200**	$	1,596,323	$	1,489,210
Average wellhead prices, net of blending costs ($/boe)	**$**	**48.72**	$	46.31	$	40.58
Total production (boe/d)		**97,680**		80,458		70,242

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; our expected exploration and development expenditures and average daily production for 2020; and our expected royalty rate and operating, transportation, general and administrative and interest expenses for 2020; our expected lease expenditures and asset retirement obligations settled in 2020; the existence, operation and strategy of our risk management program; the reassessment of our tax filings by the Canada Revenue Agency; our intention to defend the reassessments; our view of our tax filing position; the length of time it would take to resolve the reassessments; that we would owe cash taxes and late payment interest if the reassessment is successful; 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 we may issue debt or equity securities from time to time or sell assets; our intent to fund certain financial obligations with cash flow from operations and the expected timing of the financial obligations; and our plans with respect to asset retirement obligation activities. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: the timing of receipt of regulatory and shareholder approvals for the Transaction; the ability of the combined company to realize the anticipated benefits of the Transaction; 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; 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; public perception and its influence on the regulatory regime; restrictions or costs imposed by climate change initiatives; 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; 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, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission not later than March 31, 2020 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.

RISK FACTORS

We are focused on long-term strategic planning and have identified key risks, uncertainties and opportunities associated with our business that can impact the financial and operational results. Listed below is a description of these risks and uncertainties. Further information regarding risks and uncertainties affecting our business is contained in our Annual Information Form for the year ended December 31, 2019 under the "Risk Factors" section.

Volatility of oil and natural gas prices and price differentials

Our financial condition is substantially dependent on, and highly sensitive to, the prevailing prices of crude oil and natural gas. Low prices for crude oil and natural gas produced by us could have a material adverse effect on our operations, financial condition and the value and amount of our reserves.

Prices for crude oil and natural gas fluctuate in response to changes in the supply of, and demand for, crude oil and natural gas, market uncertainty and a variety of additional factors beyond our control. Crude oil prices are primarily determined by international supply and demand. Factors which affect crude oil prices include the actions of OPEC, the condition of the Canadian, United States, European and Asian economies, government regulation, political stability in the Middle East and elsewhere, the supply of crude oil in North America and internationally, the ability to secure adequate transportation for products, the availability of alternate fuel sources and weather conditions. Natural gas prices realized by us are affected primarily in North America by supply and demand, weather conditions, industrial demand, prices of alternate sources of energy and developments related to the market for liquefied natural gas. All of these factors are beyond our control and can result in a high degree of price volatility. Fluctuations in currency exchange rates further compound this volatility when commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars.

Our financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between our light/medium oil and heavy oil (in particular the light/heavy differential) and quoted market prices. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as transportation costs, capacity and interruptions, refining demand, storage capacity, the availability and cost of diluents used to blend and transport product and the quality of the oil produced, all of which are beyond our control. In addition, there is not sufficient pipeline capacity for Canadian crude oil to access the American refinery complex or tidewater to access world markets and the availability of additional transport capacity via rail is more expensive and variable, therefore, the price for Canadian crude oil is very sensitive to pipeline and refinery outages, which contributes to this volatility.

Decreases to or prolonged periods of low commodity prices, particularly for oil, may negatively impact our ability to meet guidance targets, maintain our business and meet all of our financial obligations as they come due. It could also result in the shut-in of currently producing wells without an equivalent decrease in expenses due to fixed costs, a delay or cancellation of existing or future drilling, development or construction programs, un-utilized long-term transportation commitments and a reduction in the value and amount of our reserves.

We conduct assessments of the carrying value of our assets in accordance with IFRS. If crude oil and natural gas forecast prices decline, the carrying value of our assets could be subject to downward revisions and our net earnings could be adversely affected.

The amount of oil and natural gas that we can produce and sell is subject to the availability and cost of gathering, processing and pipeline systems

We deliver our products through gathering, processing and pipeline systems which we do not own and purchasers of our products rely on third party infrastructure to deliver our products to market. The lack of access to capacity in any of the gathering, processing and pipeline systems could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. Alternately, a substantial decrease in the use of such systems can increase the cost we incur to use them. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could harm our business and, in turn, our financial condition. A significant change may result from the conversion of most of the capacity on the Enbridge mainline from the common carrier model, which will end on July 1, 2021, to a contracted service model, where only shippers who sign long term transportation agreements will have access.

Access to the pipeline capacity for the transport of crude oil into the United States has become inadequate for the amount of Canadian production being exported to the United States and no pipeline capacity to tidewater allowing access to world markets has been constructed. This has resulted in significantly lower prices being realized by Canadian producers compared with the WTI price and the Brent price for crude oil. Although pipeline expansions are ongoing, the lack of pipeline capacity continues to affect the oil and natural gas industry in Canada and limit the ability to produce and to market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas from Canada. There can be no certainty that investment in pipelines, which would result in additional long-term take-away capacity, will be made by applicable third party pipeline providers or that any requisite applications will receive regulatory approval. There is also no certainty that short-term operational constraints on pipeline systems, arising from pipeline interruption and/or increased supply of crude oil, will not occur.

There is no certainty that crude-by-rail transportation and other alternative types of transportation for our production will be sufficient to address any gaps caused by operational constraints on pipeline systems. In addition, our crude-by-rail shipments may be impacted by service delays, inclement weather, derailment or blockades and could adversely impact our crude oil sales volumes or the price received for our product. Crude oil produced and sold by us may be involved in a derailment or incident that results in legal liability or reputational harm.

A portion of our production may be processed through facilities controlled by third parties. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuance or decrease of operations could materially adversely affect our ability to process our production and to deliver the same for sale.

Failure to comply with the covenants in the agreements governing our debt could adversely affect our financial condition

We are required to comply with the covenants in our credit facilities and long-term notes. If we fail to comply with such covenants, are unable to pay the debt service charges or otherwise commit an event of default, such as bankruptcy, it could result in the seizure and/or sale of our assets by our secured creditors. The proceeds from any sale of our assets would be applied to satisfy amounts owed to the secured creditors and then unsecured creditors. Only after the proceeds of that sale were applied towards our debt would the remainder, if any, be available for the benefit of our shareholders.

Availability and cost of capital or borrowing to maintain and/or fund future development and acquisitions

The future development of our business may be dependent on our ability to obtain additional capital including, but not limited to, debt and equity financing. Unpredictable financial markets and the associated credit impacts may impede our ability to secure and maintain cost effective financing and limit our ability to achieve timely access to capital markets on acceptable terms and conditions. If external sources of capital become limited or unavailable, our ability to make capital investments, continue our business plan, meet all of our financial obligations as they come due and maintain existing properties may be impaired. Should a lack of financing and uncertainty in the capital markets adversely impact our ability to refinance debt, additional equity may be issued which could have a dilutive effect on Shareholders. Additionally, from time to time, we may issue securities from treasury in order to reduce debt, complete acquisitions and/or optimize our capital structure.

Our ability to obtain additional capital is dependent on, among other things, a general interest in energy industry investments and, in particular, interest in our securities along with our ability to maintain our credit ratings. If we are unable to maintain our indebtedness and financial ratios at levels acceptable to our credit rating agencies, or should our business prospects deteriorate, our credit ratings could be downgraded, which would adversely affect the value of our outstanding securities and existing debt and our ability to obtain new financing and may increase our borrowing costs.

From time to time we may enter into transactions which may be financed in whole or in part with debt. The level of our indebtedness from time to time, could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Our credit facilities may not provide sufficient liquidity and a failure to renew our credit facilities could adversely affect our financial condition

Our credit facilities and any replacement credit facilities may not provide sufficient liquidity. The amounts available under our credit facilities may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms attractive to us, if at all. There can be no assurance that the amount of our credit facilities will be adequate for our future financial obligations, including future capital expenditures, or that we will be able to obtain additional funds. In the event we are unable to refinance our debt obligations, it may impact our ability to fund ongoing operations. In the event that the credit facilities are not extended before April 2, 2024, indebtedness under the credit facilities will be repayable at that time. There is also a risk that the credit facilities will not be renewed for the same amount or on the same terms. In addition, we are required to repay the long-term notes at maturity.

We are not the operator of our drilling locations in our Eagle Ford acreage and, therefore, we will not be able to control the timing of development, associated costs or the rate of production of that acreage

Marathon Oil EF LLC ("Marathon Oil"), a wholly owned subsidiary of Marathon Oil Corporation (NYSE: MRO), is the operator of our Eagle Ford acreage and we are reliant upon Marathon Oil to operate successfully. Marathon Oil will make decisions based on its own best interest and the collective best interest of all of the working interest owners of this acreage, which may not be in our best interest. We have a limited ability to exercise influence over the operational decisions of Marathon Oil, including the setting of capital expenditure budgets and determination of drilling locations and schedules. The success and timing of development activities, operated by Marathon Oil, will depend on a number of factors that will largely be outside of our control, including:

- the timing and amount of capital expenditures;
- Marathon Oil's expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production of reserves, if any.

To the extent that the capital expenditure requirements related to our Eagle Ford acreage exceeds our budgeted amounts, it may reduce the amount of capital we have available to invest in our other assets. We have the ability to elect whether or not to participate in well locations proposed by Marathon Oil on an individual basis. If we elect to not participate in a well location, we forgo any revenue from such well until Marathon Oil has recouped, from our working interest share of production from such well, 300% to 500% of our working interest share of the cost of such well.

Our financial performance is significantly affected by the cost of developing and operating our assets

Our development and operating costs are affected by a number of factors including, but not limited to: price inflation; scheduling delays; trucking and fuel costs; failure to maintain quality construction standards; the cost of new technologies and supply chain disruptions, including access to skilled labour. Natural gas, electricity, water, diluent, chemicals, supplies, reclamation, abandonment and labour costs are examples of operating and other costs that are susceptible to significant fluctuation.

Our oil and natural gas reserves are a depleting resource and decline as such reserves are produced

Our future oil and natural gas reserves and production, and therefore our cash flow from operating activities, will be highly dependent on our success in exploiting our reserves base and acquiring additional reserves. The business of exploring for, developing or acquiring reserves is capital intensive. If external sources of capital become limited or unavailable on commercially reasonable terms, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves may be impaired.

There is no assurance we will be successful in developing our reserves or acquiring additional reserves at acceptable costs. Without these reserves additions, our reserves will deplete and as a consequence production from and the average reserve life of our properties will decline, which may adversely affect the value of our outstanding securities.

Our ability to add to our oil and natural gas reserves is highly dependent on our success in exploiting existing properties and acquiring additional reserves

Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. Future oil and natural gas exploration may involve unprofitable efforts, not only from unsuccessful wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit. Completion of a well does not assure a profit on the investment. Drilling hazards or environmental liabilities or damages could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays or failure in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow from operating activities to varying degrees. New wells we drill or participate in may not become productive and we may not recover all or any portion of our investment in these wells.

Public perception and its influence on the regulatory regime

Concern over the impact of oil and gas development on the environment and climate change has received considerable attention in the media and recent public commentary, and the social value proposition of resource development is being challenged. Additionally, certain pipeline leaks, rail car derailments, major weather events and induced seismicity events have gained media, environmental and other stakeholder attention. Future laws and regulation may be impacted by such incidents, which could have a material adverse effect on our financial condition, results of operations or prospects.

Climate change initiatives may impose restrictions or costs on our business which have a material adverse affect on our business

Our exploration and production facilities and other operational activities emit GHGs. As such, it is highly likely that GHG emissions regulation (including carbon taxes) enacted in jurisdictions where we operate will impact us.

Negative consequences which could result from new GHG emissions regulation include, but are not limited to: increased operating costs; increased construction and development costs; additional monitoring and compliance costs; a requirement to redesign or retrofit current facilities; permitting delays; additional costs associated with the purchase of emission credits or allowances; and reduced demand for crude oil. Additionally, if GHG emissions regulation differs by region or type of production, all or part of our production could be subject to costs which are disproportionately higher than those of other producers.

The direct or indirect costs of compliance with GHG emissions regulation may have a material adverse affect on our business, financial condition, results of operations and prospects. At this time, it is not possible to predict whether compliance costs will have a material adverse affect on our business.

Although we provide for the necessary amounts in our annual capital budget to fund our currently estimated obligations, there can be no assurance that we will be able to satisfy our actual future obligations associated with GHG emissions from such funds.

Implementation of new regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes, adversely affecting the Company's financial position

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Hydraulic fracturing has featured prominently in recent political, media and activist commentary on the subject of water usage, induced seismicity events and environmental damage. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Company's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Regulatory water use restrictions and/or limited access to water or other fluids may impact the Company's ability to fracture its wells or carry out waterflood operations

The Company undertakes or intends to undertake certain hydraulic fracturing and waterflooding programs. To undertake such operations the Company needs to have access to sufficient volumes of water, or other liquids. There is no certainty that the Company will have access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as hydraulic fracturing and waterflooding. If the Company is unable to access such water it may not be able to undertake hydraulic fracturing or waterflooding activities, which may reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reservoirs.

Changes in government controls, legislation or regulations that affect the oil and gas industry, or failing to comply with such controls, legislation or regulations, could adversely affect us

The oil and gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and, with respect to pricing and taxation of oil and natural gas, by agreements among the governments of Canada, Alberta, Saskatchewan, the United States and Texas, all of which should be carefully considered by investors in the oil and gas industry. All such controls, regulations and legislation are subject to revocation, amendment or administrative change, some of which have historically been material and in some cases materially adverse and there can be no assurance that there will not be further revocation, amendment or administrative change which will be materially adverse to our assets, reserves, financial condition, results of operations or prospects.

The oil and gas industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, oil sands or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields (including restrictions on production) and possibly expropriation or cancellation of contract rights.

Other government controls, legislation or regulations may change from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing controls, legislation or regulations, the implementation of new controls, legislation or regulations or the modification of existing controls, legislation or regulations affecting the oil and gas industry could reduce demand for crude oil and natural gas, increase our costs, or delay or restrict our operations, all of which would have a material adverse effect on us. In addition, failure to comply with government controls, legislation or regulations may result in the suspension, curtailment or termination of operations and subject us to liabilities and administrative, civil and criminal penalties. Compliance costs can be significant.

Regulations regarding the disposal of fluids used in the Company's operations may increase its costs of compliance or subject it to regulatory penalties or litigation

The safe disposal of hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal and provincial governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase the Company's costs of compliance.

The oil and gas industry is highly regulated and changes in environmental, health and safety controls, legislation or regulations may impose restrictions, costs or other liabilities which may have an adverse affect on our business

All phases of our operations are subject to environmental, health and safety regulation pursuant to a variety of Canadian, U.S. and other federal, provincial, state and municipal laws and regulations (collectively, "**environmental regulations**") governing occupational health and safety aspects of our operations, the spill, release or emission of materials into the environment or otherwise relating to environmental protection. Environmental regulations require that wells, facility sites and other properties associated with our operations be constructed, operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects and changes to certain existing projects, may require the submission and approval of environmental impact assessments or permit applications. Environmental regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. It also imposes restrictions, liabilities and obligations in connection with the management of fresh or potable water sources that are being used, or whose use is contemplated, in connection with oil and gas operations. The provinces of Alberta and Saskatchewan have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes in the ratio of our deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted, the timing of our abandonment and reclamation operations and the costs associated with such operations.

Compliance with environmental regulations can require significant expenditures, including expenditures for clean-up costs and damages arising out of contaminated properties. Failure to comply with environmental regulations may result in the imposition of administrative, civil and criminal penalties or issuance of clean up orders in respect of us or our properties, some of which may be material. We may also be exposed to civil liability for environmental matters or for the conduct of third parties, including private parties commencing actions and new theories of liability, regardless of negligence or fault. Although it is not expected that the costs of complying with environmental regulations will have a material adverse effect on our financial condition or results of operations, no assurance can be made that the costs of complying with environmental regulations in the future will not have such an effect. The implementation of new environmental regulations or the modification of existing environmental regulations affecting the oil and gas industry generally could reduce demand for crude oil and natural gas, resulting in stricter standards and enforcement, larger penalties and liability and increased capital expenditures and operating costs, which could have a material adverse effect on our financial condition, results of operations or prospects.

In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, our business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada) and in the United States by the Hart-Scott-Rodino Antitrust Improvements Act.

Variations in interest rates and foreign exchange rates could adversely affect our financial condition

There is a risk that interest rates will increase given the current historical low level of interest rates. An increase in interest rates could result in a significant increase in the amount we pay to service debt and could have an adverse effect on our financial condition, results of operations and future growth which may adversely affect the value of our outstanding securities.

World oil prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canada/U.S. foreign exchange rate that may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact our revenues. A substantial portion of our operations and production are in the United States and, as such, we are exposed to foreign currency risk on both revenues and costs to the extent the value of the Canadian dollar decreases relative to the U.S. dollar. In addition, we are exposed to foreign currency risk as a large portion of our indebtedness is denominated in U.S. dollars and the interest payable thereon is payable in U.S. dollars. Future Canada/U.S. foreign exchange rates could also impact the future value of our reserves as determined by our independent evaluator.

A decline in the value of the Canadian dollar relative to the United States dollar provides a competitive advantage to United States companies acquiring Canadian oil and gas properties and may make it more difficult for us to replace reserves through acquisitions.

Our hedging activities may negatively impact our income and our financial condition

In response to fluctuations in commodity prices, foreign exchange and interest rates, we may utilize various derivative financial instruments and physical sales contracts to manage our exposure under a hedging program. The terms of these arrangements may limit the benefit to us of favourable changes in these factors, including receiving less than the market price for our production, and may also result in us paying royalties at a reference price which is higher than the hedged price. We may also suffer financial loss due to hedging arrangements if we are unable to produce oil or natural gas to fulfill our delivery obligations. There is also increased exposure to counterparty credit risk. To the extent that our current hedging agreements are beneficial to us, these benefits will only be realized for the period and for the commodity quantities in those contracts. In addition, there is no certainty that we will be able to obtain additional hedges at prices that have an equivalent benefit to us, which may adversely impact our revenues in future periods.

Income tax laws or other laws or government incentive programs or regulations relating to our industry may in the future be changed or interpreted in a manner that adversely affects us and our Shareholders

We file all required income tax returns and believe that we are in full compliance with the applicable tax legislation. However, such returns are subject to audit and reassessment by the applicable taxation authority. Any such reassessment may have an impact on current and future taxes payable. At present, the Canadian tax authorities have reassessed the returns of certain of our subsidiaries.

Tax authorities having jurisdiction over us or our Shareholders may disagree with the manner in which we calculate our income for tax purposes or could change their administrative practices to our detriment or the detriment of our Shareholders. In addition, income tax laws and government incentive programs relating to the oil and gas industry may change in a manner that adversely affects the market price of the Common Shares.

There are numerous uncertainties inherent in estimating quantities of recoverable oil and natural gas reserves, including many factors beyond our control

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. In general, estimates of economically recoverable oil and natural gas reserves and the future net revenues therefrom are based upon a number of factors and assumptions made as of the date on which the reserves estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies, historical production from the properties, initial production rates, production decline rates, the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities and estimates of future commodity prices and capital costs, all of which may vary considerably from actual results.

All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Our reserves as at December 31, 2019 are estimated using forecast prices and costs. If we realize lower prices for crude oil, natural gas liquids and natural gas and they are substituted for the estimated price assumptions, the present value of estimated future net revenues for our reserves and net asset value would be reduced and the reduction could be significant. Our actual production, revenues, royalties, taxes and development, abandonment and operating expenditures with respect to our reserves will likely vary from such estimates, and such variances could be material.
Estimates of reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations in the previously estimated reserves and such variances could be material.

Acquiring, developing and exploring for oil and natural gas involves many hazards. We have not insured and cannot fully insure against all risks related to our operations

Our crude oil and natural gas operations are subject to all of the risks normally incidental to the: (i) storing, transporting, processing, refining and marketing of crude oil, natural gas and other related products; (ii) drilling and completion of crude oil and natural gas wells; and (iii) operation and development of crude oil and natural gas properties, including, but not limited to: encountering unexpected formations or pressures; premature declines of reservoir pressure or productivity; blowouts; fires; explosions; equipment failures and other accidents; gaseous leaks; uncontrollable or unauthorized flows of crude oil, natural gas or well fluids; migration of harmful substances; oil spills; corrosion; adverse weather conditions; pollution; acts of vandalism and terrorism; and other adverse risks to the environment.

Although we maintain insurance in accordance with customary industry practice, we are not fully insured against all of these risks nor are all such risks insurable and in certain circumstances we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. In addition, the nature of these risks is such that liabilities could exceed policy limits, in which event we could incur significant costs that could have a material adverse effect on our business, financial condition, results of operations and prospects.

We are subject to risk of default by the counterparties to our contracts and our counterparties may deem us to be a default risk

We are subject to the risk that counterparties to our risk management contracts, marketing arrangements and operating agreements and other suppliers of products and services may default on their obligations under such agreements or arrangements, including as a result of liquidity requirements or insolvency. Furthermore, low oil and natural gas prices increase the risk of bad debts related to our joint venture and industry partners. A failure by such counterparties to make payments or perform their operational or other obligations to us may adversely affect our results of operations, cash flow from operating activities and financial position. Conversely, our counterparties may deem us to be at risk of defaulting on our contractual obligations. These counterparties may require that we provide additional credit assurances by prepaying anticipated expenses or posting letters of credit, which would decrease our available liquidity and increase our costs.

We are subject to a number of additional business risks which could adversely affect our income and financial condition

Our business involves many operating risks related to acquiring, developing and exploring for oil and natural gas which even a combination of experience, knowledge and careful evaluation may not be able to overcome. Our operational risks include, but are not limited to: operational and safety considerations; pipeline and rail transportation and interruptions; reservoir performance and technical challenges; partner risks; competition; land claims; our ability to hire and retain necessary skilled personnel; the availability of drilling and related equipment; our ability to access new technology; seasonality and access restrictions; timing and success of integrating the business and operations of acquired assets and companies; risk of litigation, regulatory issues, increases in government taxes and changes to royalty or mineral/severance tax regimes; and risk to our reputation resulting from operational activities that may cause personal injury, property damage or environmental damage.

We may participate in larger projects and may have more concentrated risk in certain areas of our operations

We have a variety of exploration, development and construction projects underway at any given time. Project delays may result in delayed revenue receipts and cost overruns may result in projects being uneconomic. Our ability to complete projects is dependent on general business and market conditions as well as other factors beyond our control, including the availability of skilled labour and manpower, the availability and proximity of pipeline capacity and rail terminals, weather, environmental and regulatory matters, ability to access lands, availability of drilling and other equipment and supplies, and availability of processing capacity.

Our thermal heavy oil projects face additional risks compared to conventional oil and gas production

Our thermal heavy oil projects are capital intensive projects which rely on specialized production technologies. Certain current technologies for the recovery of heavy oil, such as CSS and SAGD, are energy intensive, requiring significant consumption of natural gas and other fuels in the production of steam that is used in the recovery process. The amount of steam required in the production process varies and therefore impacts costs. The performance of the reservoir can also affect the timing and levels of production using new technologies. A large increase in recovery costs could cause certain projects that rely on CSS, SAGD or other new technologies to become uneconomic, which could have an adverse effect on our financial condition and our reserves. There are risks associated with growth and other capital projects that rely largely or partly on new technologies and the incorporation of such technologies into new or existing operations. The success of projects incorporating new technologies cannot be assured.

Project economics and our earnings may be reduced if increases in operating costs are incurred. Factors which could affect operating costs include, without limitation: labour costs; the cost of catalysts and chemicals; the cost of natural gas and electricity; water handling and availability; power outages; produced sand causing issues of erosion, hot spots and corrosion; reliability of facilities; maintenance costs; the cost to transport sales products; and the cost to dispose of certain by-products.

Alternatives to and changing demand for petroleum products

Conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy could reduce demand for oil and natural gas. Certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar effect on the demand for oil and gas products. The Company cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Company's business and financial condition by decreasing its cash flow from operating activities and the value of its assets.

Our information technology systems are subject to certain risks

We utilize a number of information technology systems for the administration and management of our business. If our ability to access and use these systems is interrupted and cannot be quickly and easily restored then such event could have a material adverse effect on us. Furthermore, although our information technology systems are considered to be secure, if an unauthorized party is able to access the systems then such unauthorized access may compromise our business in a materially adverse manner.