Committed to building a

BRIGHT FUTURE

2019

Annual Report

TSX BTE | NYSE BTE

Our Highlights

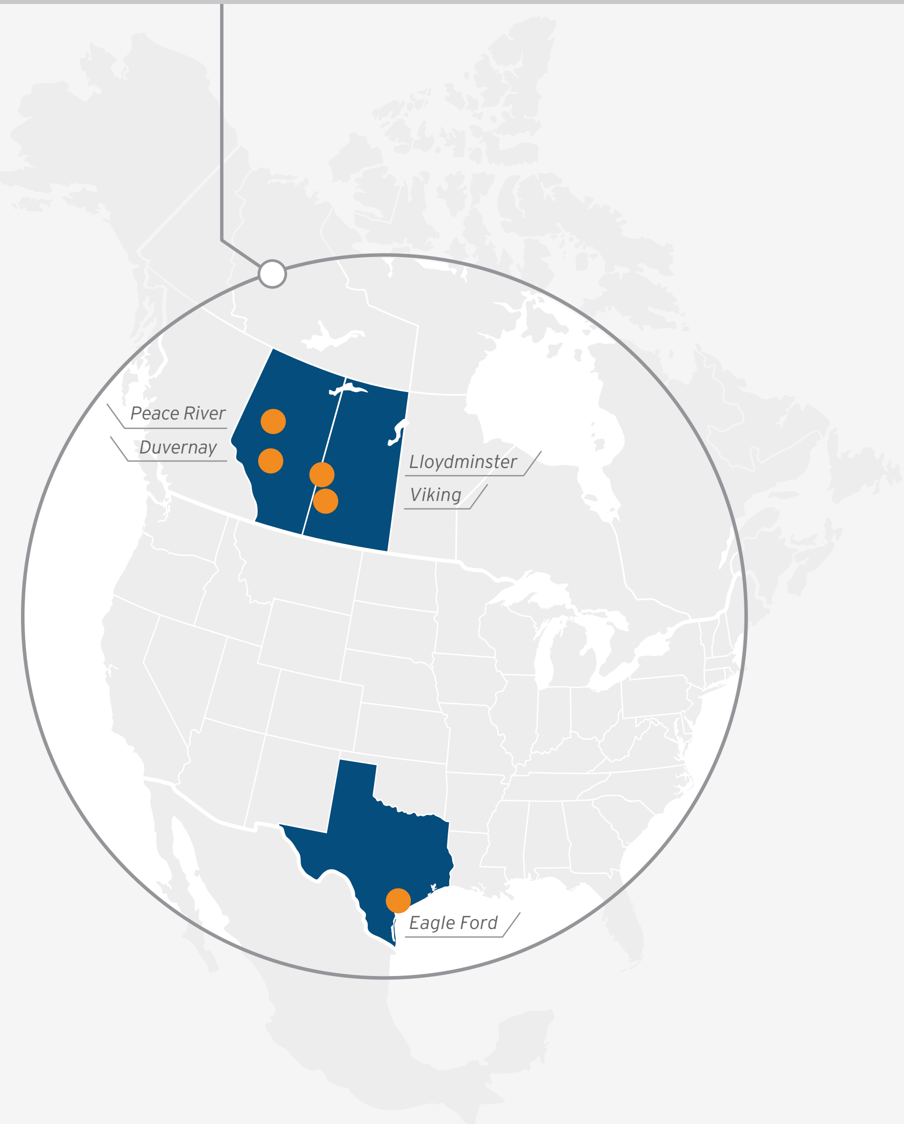
97,680 boe/d
for the full-year 2019

$1.01 billion
of EBITDA for the full-year 2019

17%
reduction in net debt ($393 million) in 2019

112%
production replacement from development activities

Our Operating Areas



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SUMMARY

	Years Ended	
	December 31, 2019	December 31, 2018
FINANCIAL (thousands of Canadian dollars, except per common share amounts)		
Petroleum and natural gas sales	**$ 1,805,919**	$ 1,428,870
Adjusted funds flow (1)	**902,426**	472,983
Per share - basic	**1.62**	1.35
Per share - diluted	**1.62**	1.35
Net income (loss)	**(12,459)**	(325,309)
Per share - basic	**(0.02)**	(0.93)
Per share - diluted	**(0.02)**	(0.93)
Capital Expenditures		
Exploration and development expenditures (1)	**$ 552,291**	$ 495,721
Acquisitions, net of divestitures	**2,180**	1,603,850
Total oil and natural gas capital expenditures	**$ 554,471**	$ 2,099,571
Net Debt		
Bank loan (2)	**$ 506,471**	$ 522,294
Long-term notes (2)	**1,337,200**	1,596,323
Long-term debt	**1,843,671**	2,118,617
Working capital deficiency	**28,120**	146,550
Net debt (1)	**$ 1,871,791**	$ 2,265,167
Shares Outstanding - basic (thousands)		
Weighted average	**557,048**	351,542
End of period	**558,305**	554,060

		Years Ended	
		December 31, 2019	December 31, 2018
OPERATING			
Daily Production			
Light oil and condensate (bbl/d)		**43,587**	29,264
Heavy oil (bbl/d)		**26,741**	25,954
NGL (bbl/d)		**10,229**	9,745
Total liquids (bbl/d)		**80,557**	64,963
Natural gas (mcf/d)		**102,742**	92,971
Oil equivalent (boe/d @ 6:1) [3]		**97,680**	80,458
Netback (thousands of Canadian dollars)			
Total sales, net of blending and other expense [4]	**$**	**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
General and administrative		**(45,469)**	(45,825)
Cash financing and interest		**(107,417)**	(104,318)
Realized financial derivatives gain (loss)		**75,620**	(73,165)
Other [5]		**4,467**	(1,532)
Adjusted funds flow [1]	**$**	**902,426**	$ 472,983
Netback (per boe)			
Total sales, net of blending and other expense [4]	**$**	**48.72**	$ 46.31
Royalties		**(8.98)**	(10.68)
Operating expense		**(11.16)**	(10.61)
Transportation expense		**(1.23)**	(1.26)
Operating netback [1]	**$**	**27.35**	$ 23.76
General and administrative		**(1.28)**	(1.56)
Cash financing and interest		**(3.01)**	(3.55)
Realized financial derivatives (loss) gain		**2.12**	(2.49)
Other [5]		**0.13**	(0.05)
Adjusted funds flow [1]	**$**	**25.31**	$ 16.11

Notes:

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

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

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

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

(5) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and payments on onerous contracts. Refer to the 2019 MD&A for further information on these amounts.

Advisory Regarding Forward-Looking Statements

In the interest of providing Baytex's shareholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements in this report 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", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this report speak only as of the date thereof and are expressly qualified by this cautionary statement.

Specifically, this report contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; that we have flexibility to execute our business plan driving free cash flow and strengthening our balance sheet; our 2020 production and capital expenditure guidance; that our exploration and development program is expended to be fully funded by adjusted funds flow at the forward strip and we have flexibility to adjust our spending plans; the percentage of our net crude oil exposure that is hedged for 2020; that after completing the announced redemption of long-term notes our credit facilities will be one-third undrawn, we will have over $300 million of liquidity and the weighted average cost of our debt will be approximately 6%; that we have a strong drilling inventory of approximately 10 or more years in each core asset; we are committed to stable production, generating free cash flow and strengthening our balance sheet.

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 they can be profitably produced in the future.

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

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

These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2019, 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.

All amounts in this report are stated in Canadian dollars unless otherwise specified.

Non-GAAP Financial and Capital Management Measures

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

Adjusted funds flow is not a measurement based on generally accepted accounting principles ("GAAP") in Canada, but is a financial term commonly used in the oil and gas industry. We define adjusted funds flow as cash flow from operating activities adjusted for changes in non-cash operating working capital and asset retirement obligations settled. Our determination of adjusted funds flow may not be comparable to other issuers. We consider adjusted funds flow a key measure that provides a more complete understanding of operating performance and our ability to generate funds for exploration and development expenditures, debt repayment, settlement of our abandonment obligations and potential future dividends. In addition, we use a ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. Changes in non-cash working capital are eliminated in the determination of adjusted funds flow as the timing of collection, payment and incurrence is variable and by excluding them from the calculation we are able to provide a more meaningful measure of our cash flow on a continuing basis. For a reconciliation of adjusted funds flow to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the year ended December 31, 2019.

EBITDA is not a measurement based on GAAP in Canada. EBITDA is defined as net income or loss adjusted for financing and interest expenses, unrealized gains and losses on financial derivatives, income tax, non-recurring losses, payments on lease obligations, certain specific unrealized and non-cash transactions (including depletion, exploration and evaluation expenses, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation).

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

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

Net debt is not a measurement based on GAAP in Canada. We define net debt to be the sum of cash, trade and other accounts receivable, trade and other accounts payable, and the principal amount of both the long-term notes and the bank loan. Our definition of net debt may not be comparable to other issuers. We believe that this measure assists in providing a more complete understanding of our cash liabilities and provides a key measure to assess our liquidity. We use the principal amounts of the 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 capital or repayment obligation.

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

MESSAGE TO SHAREHOLDERS

While we have been a publicly listed corporation for more than 25 years, we are taking steps to systematically transform Baytex. We are now a company with a diversified North American oil portfolio designed to generate free cash flow. We have shifted our portfolio to predominantly high operating netback, light oil assets while also reducing our cash cost structure and improving capital efficiencies. More recently, we have refinanced our long-term notes and extended the term of our revolving credit facilities to 2024. These steps give us the confidence and flexibility to execute our business plan to continue driving free cash flow and strengthening our balance sheet.

Despite the many challenges facing our industry today, we recognize that developing environmentally and socially responsible energy plays an important role in raising the standard of living for people around the world. In 2019 we continued our excellent health, safety and environmental performance and published our fourth biennial corporate sustainability report. This report demonstrates our commitment to transparency and to managing the environmental and social impacts of our business. We have elevated our standards, establishing a target to reduce our greenhouse gas emissions intensity by 30% over the next three years. We believe our safety and environmental leadership will serve us well as we continue to adapt to changing market conditions.

We have a high quality and diversified oil portfolio and our operating teams are well established with a track record of delivering results. In Canada, we have one of the largest conventional oil portfolios, including high operating netback, light oil production in the Viking and low decline, heavy oil production at Peace River and Lloydminster. We also hold a dominant land position in the emerging light oil resource play in the East Shale Duvernay, which has similar geologic and reservoir characteristics to our Eagle Ford shale asset in the United States. Our position in the Eagle Ford is defined by one of the highest quality, lowest-cost U.S. resource plays with outstanding drilling economics.

Our 2019 operating and financial results demonstrate the benefits of this diversified oil weighted portfolio and our commitment to allocate capital effectively, generate free cash flow and further strengthen our balance sheet. We produced 97,680 boe/d (82% liquids) and exceeded the high end of our annual guidance with capital expenditures at the low end of guidance totaling $552 million. This resulted in the following financial results:

- EBITDA of $1 billion and free cash flow of $329 million.
- Net debt reduction of 17%, or $393 million, due to the strong free cash flow and a strengthening of the Canadian dollar relative to the U.S. dollar.
- Redeemed our US$150 million principal amount of 6.75% senior unsecured notes nearly two years early.

We also demonstrated reserves growth with proved developed producing reserves increasing 5%, finding & development costs of $13/boe and a recycle ratio of 2.3x. In aggregate, we replaced 112% of 2019 production, adding 40 million boe of proved plus probable reserves through development activities. In the Eagle Ford, strong well performance continues to be driven by enhanced completions across our acreage position. In the Viking, over 90% of our drilling is now comprised of extended reach horizontal wells. In our heavy oil assets we delivered stable production with limited capital investment. We also continued to advance our Duvernay shale light oil asset with two strong wells in the East Shale Basin.

Subsequent to year-end, we issued US$500 million principal amount of 8.75% senior unsecured notes, maturing on April 1, 2027 which enabled us to redeem two series of notes; US$400 million principal amount of 5.125% senior unsecured notes due June 1, 2021 and $300 million principal amount of 6.625% senior unsecured notes due July 19, 2022. Following the redemption of these notes, our next long-term note maturity is June 2024.

We also extended the maturities of our revolving credit facilities and term loan to April 2, 2024. These credit facilities, which total $1.046 billion, are not borrowing base facilities and do not require annual or semi-annual reviews. Following all of these steps, our credit facilities are approximately one-third undrawn and we retain over $300 million of liquidity with a weighted average interest rate on our long-term debt of approximately 6%.

Looking Forward

We maintain an attractive and deep inventory of development locations with approximately ten years or more of remaining drilling opportunities in each of our core assets. We remain committed to delivering stable production, maximizing free cash flow and further strengthening our balance sheet.

Our 2020 annual guidance is unchanged as we target production of 93,000 to 97,000 boe/d with exploration and development expenditures of $500 to $575 million. At the time of writing, our exploration and development program is expected to be fully funded from adjusted funds flow at the forward strip and we have the operational flexibility to adjust our spending plans based on changes in commodity prices.

We maintain a consistent approach to risk management and marketing, utilizing various financial derivative contracts and crude-by-rail to reduce the volatility in our adjusted funds flow. For 2020, we have entered into hedges on approximately 48% of our net crude oil exposure, largely utilizing a 3-way option structure that provides WTI price protection at US$58/bbl with upside participation to US$63/bbl. We are also contracted to deliver 11,500 bbl/d of our heavy oil volumes to market by rail.

Baytex's success is due to very engaged Board, management and employee group who are all strongly aligned and committed to driving value for shareholders. With the combined team, we are confident we have the skills, experience and focus that will create a more prosperous future.

We look forward to executing our plans in 2020 for the ongoing benefit of all stakeholders and we thank you for your continued support.

Sincerely,

Edward D. LaFehr
President and Chief Executive Officer

March 4, 2020

MANAGEMENT'S DISCUSSION AND ANALYSIS

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.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Baytex Energy Corp. (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision of our President and Chief Executive Officer and our Executive Vice President and Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on our assessment, we have concluded that as of December 31, 2019, our internal control over financial reporting was effective.

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.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2019 has been audited by KPMG LLP, the Company's Independent Registered Public Accounting Firm, who also audited the Company's consolidated financial statements for the year ended December 31, 2019.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

Management, in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board, has prepared the accompanying consolidated financial statements of the Company. Financial and operating information presented throughout this Annual Report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

KPMG LLP were appointed by the Company's Board of Directors to express an audit opinion on the consolidated financial statements. Their examination included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with IFRS.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual review of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the Independent Registered Public Accounting Firm to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of KPMG LLP and reviews their fees. The Independent Registered Public Accounting Firm has access to the Audit Committee without the presence of management.

Edward D. LaFehr
President and Chief Executive Officer
Baytex Energy Corp.

Rodney D. Gray
Executive Vice President and Chief Financial Officer
Baytex Energy Corp.

March 3, 2020

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of Baytex Energy Corp.:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated statements of financial position of Baytex Energy Corp. (the “Company”) as of December 31, 2019 and 2018, the related consolidated statements of loss and comprehensive loss, changes in equity, and cash flows for the years then ended, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its financial performance and its cash flows for the years then ended, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company’s internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 3, 2020 expressed an unqualified opinion on the effectiveness of the Company’s internal control over financial reporting.

Basis for Opinion

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

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

Critical Audit Matters

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

Assessment of indicators of impairment or impairment reversal related to oil and gas properties

As discussed in note 3 to the consolidated financial statements, when circumstances indicate that a cash-generating unit (“CGU”) may be impaired or a previous impairment reversed, the Company compares the carrying amount of the CGU to its recoverable amount. At each reporting date, the Company analyzes indicators of impairment or impairment reversal (“impairment indicators”) for each CGU, such as significant increases or decreases in reservoir performance (which includes forecasted production volumes), forecasted royalty, operating and capital costs and forecasted oil and gas prices (collectively “reserve assumptions”) or resulting cash flows from proved and probable oil and gas reserves (“CGU reserves”). The estimation of CGU reserves involves the expertise of independent reservoir engineering specialists, who take into consideration reserve assumptions. The Company engages independent reservoir engineering specialists to estimate CGU reserves, which are an input in the assessment of CGU impairment indicators. The carrying amount of the Company’s oil and gas properties as at December 31, 2019 was $5,388 million.

We identified the assessment of indicators of impairment or impairment reversal related to oil and gas properties as a critical audit matter. Changes in circumstances that could indicate a CGU may be impaired or a previous impairment reversed, required the application of complex auditor judgment. Complex auditor judgment was also required to evaluate the reserve assumptions used by the Company in their assessment.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company’s impairment indicators assessment process, including controls related to the assessment of reserve assumptions and resulting cash flows of CGU reserves. We evaluated changes in circumstances to the Company or CGUs identified by the Company against evidence obtained through other procedures. We evaluated the competence, capabilities and objectivity of the independent reservoir engineering specialists, who estimated CGU reserves. We evaluated the methodology used by the independent reservoir engineering specialists to estimate CGU reserves for compliance with regulatory standards. We compared current year actual CGU production volumes, royalty, operating and capital costs to the respective reserve assumptions used in the prior year estimate of proved reserves by CGU to assess the Company's ability to accurately forecast. We compared the forecasted commodity prices used in the current year estimate of CGU reserves to those published by independent reservoir engineering companies. We compared the forecasted production volumes and forecasted royalty, operating and capital costs assumptions used in the current year estimate of CGU reserves to historical results.

Assessment of the recoverable amount of the Peace River cash generating unit

As discussed in note 7 to the consolidated financial statements, the Company recorded an impairment charge of $180 million related to the Peace River CGU. The Company identified an indicator of impairment at December 31, 2019 for the Peace River CGU and performed an impairment test to determine the recoverable amount of the CGU. The determination of recoverable amount of the CGU involves a number of estimates, including cash flows associated with proved and probable oil and gas reserves of the Peace River CGU ("Peace River CGU reserves") and discount rate. The estimation of Peace River CGU reserves involves the expertise of independent reservoir engineering specialists, who take into consideration reserve assumptions. The Company engages independent reservoir engineering specialists to estimate the Peace River CGU reserves.

We identified the assessment of the recoverable amount of the Peace River CGU as a critical audit matter. Complex auditor judgment was required to assess the Company's estimate of Peace River CGU reserves and discount rate, which were inputs to the calculation of recoverable amount of the Peace River CGU. Auditor judgment was also required to evaluate the reserve assumptions used to estimate Peace River CGU reserves.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company's determination of the recoverable amount of the Peace River CGU, including controls related to the development of the discount rate and the assessment of reserve assumptions and resulting cash flows of the Peace River CGU reserves. We evaluated the competence, capabilities and objectivity of the independent reservoir engineering specialists, who estimated the Peace River CGU reserves. We evaluated the methodology used by the independent reservoir engineering specialists to estimate the Peace River CGU reserves for compliance with regulatory standards. We compared current year actual CGU production volumes, royalty, operating and capital costs to the respective reserve assumptions used in the prior year estimate of the proved reserves for the Peace River CGU to assess the Company's ability to accurately forecast. We compared the forecasted commodity prices used in the current year estimate of the Peace River CGU reserves to those published by independent reservoir engineering companies. We compared the forecasted production volumes and forecasted royalty, operating and capital costs assumptions used in the current year estimate of the Peace River CGU reserves to historical results. We involved a valuation professional with specialized skills and knowledge, who assisted in evaluating the Company's discount rate, by comparing it against publicly available market and other external data. The valuation specialist estimated the recoverable amount of the Peace River CGU using the estimated of the cash flow associated with the Peace River CGU reserves and the Company's discount rate evaluated by the specialist and compared the results to market and other external pricing data.

Assessment of the impact of estimated oil and gas reserves on depletion expense related to oil and gas properties

As discussed in note 3 to the consolidated financial statements, the Company depletes its oil and gas properties using the unit-of-production method by depletable area. Under such method, capitalized costs are depleted over estimated proved and probable oil and gas reserves by depletable area ("area reserves"). For the year ended December 31, 2019, the Company recorded depletion expense related to oil and gas properties of $725 million. The estimation of area reserves requires the expertise of independent reservoir engineering specialists, who take into consideration reserve assumptions. The Company engages independent reservoir engineering specialists to estimate the area reserves.

We identified the assessment of the impact of estimated area reserves on depletion expense related to oil and gas properties as a critical audit matter. Complex auditor judgment was required to assess the Company's estimate of area reserves and the underlying reserve assumptions.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company's calculation of depletion expense, including controls over the assessment of reserve assumptions and the resulting area reserves. We evaluated the competence, capabilities and objectivity of the independent reservoir engineering specialists, who estimate area reserves. We evaluated the methodology used by the independent reservoir engineering specialists to estimate area reserves for compliance with regulatory standards. We compared current year actual area production volumes, royalty, operating and capital costs to respective reserve assumptions used in the prior year estimate of proved reserves by area to assess the Company's ability to accurately forecast. We compared the forecasted commodity prices used in the current year estimate of area reserves to those published by independent reservoir engineering firms. We compared the forecasted production volumes and forecasted royalty, operating and capital costs assumptions used in the current year estimate of area reserves to historical results.

We have served as the Company's auditor since 2016.

KPMG LLP

Chartered Professional Accountants
Calgary, Canada
March 3, 2020

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors
Baytex Energy Corp.:

Opinion on Internal Control Over Financial Reporting

We have audited Baytex Energy Corp.'s (the Company) internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission*.* In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated statements of financial position of the Company as of December 31, 2019 and 2018, and the related consolidated statements of loss, comprehensive loss, changes in equity, and cash flows for the years then ended, and related notes (collectively, the consolidated financial statements), and our report dated March 3, 2020 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

KPMG LLP

Chartered Professional Accountants
Calgary, Canada
March 3, 2020

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

As at	Notes	**December 31, 2019**	December 31, 2018
ASSETS			
Current assets			
Cash		**$ 5,572**	$ —
Trade and other receivables		**173,762**	111,564
Financial derivatives		**5,433**	79,582
		184,767	191,146
Non-current assets			
Exploration and evaluation assets	6	**320,210**	358,935
Oil and gas properties	7	**5,387,889**	5,817,889
Other plant and equipment	8	**7,598**	9,228
Lease assets	9	**13,619**	—
		$ 5,914,083	$ 6,377,198
LIABILITIES			
Current liabilities			
Trade and other payables		**$ 207,454**	$ 258,114
Lease obligations	9	**5,798**	—
Financial derivatives		**8,668**	—
Onerous contracts		**—**	1,986
Asset retirement obligations	12	**11,579**	—
		233,499	260,100
Non-current liabilities			
Bank loan	10	**505,412**	520,700
Long-term notes	11	**1,328,175**	1,583,240
Lease obligations	9	**8,085**	—
Asset retirement obligations	12	**656,395**	646,898
Deferred income tax liability	17	**235,308**	310,836
		2,966,874	3,321,774
SHAREHOLDERS' EQUITY			
Shareholders' capital	13	**5,718,835**	5,701,516
Contributed surplus		**17,712**	19,137
Accumulated other comprehensive income		**556,224**	667,874
Deficit		**(3,345,562)**	(3,333,103)
		2,947,209	3,055,424
		$ 5,914,083	$ 6,377,198

Commitments and contingencies (note 22)
Subsequent events (notes 10 and 11)

See accompanying notes to the consolidated financial statements.

Naveen Dargan
Director, Baytex Energy Corp.

Gregory K. Melchin
Director, Baytex Energy Corp.

Baytex Energy Corp.
Consolidated Statements of Loss and Comprehensive Loss
(thousands of Canadian dollars, except per common share amounts)

Years Ended December 31	Notes	2019	2018
Revenue, net of royalties			
Petroleum and natural gas sales	16	**$ 1,805,919**	$ 1,428,870
Royalties		**(320,241)**	(313,754)
		1,485,678	1,115,116
Expenses			
Operating		**397,716**	311,592
Transportation		**43,942**	36,869
Blending and other		**68,795**	68,832
General and administrative		**45,469**	45,825
Transaction costs	4	**—**	13,074
Exploration and evaluation	6	**11,764**	21,729
Depletion and depreciation	7, 8, 9	**731,686**	558,684
Impairment	6, 7	**187,822**	285,341
Share-based compensation	14	**15,894**	19,534
Financing and interest	18	**125,865**	119,086
Financial derivatives loss (gain)	20	**7,197**	(43,550)
Foreign exchange (gain) loss	19	**(61,787)**	108,294
Gain on dispositions		**(2,238)**	(1,946)
Other income		**(7,526)**	(1,172)
		1,564,599	1,542,192
Net loss before income taxes		**(78,921)**	(427,076)
Income tax expense (recovery)	17		
Current income tax expense (recovery)		**2,093**	(35)
Deferred income tax recovery		**(68,555)**	(101,732)
		(66,462)	(101,767)
Net loss attributable to shareholders		**$ (12,459)**	$ (325,309)
Other comprehensive income (loss)			
Foreign currency translation adjustment		**(111,650)**	204,770
Comprehensive loss		**$ (124,109)**	$ (120,539)
Net loss per common share	15		
Basic		**$ (0.02)**	$ (0.93)
Diluted		**$ (0.02)**	$ (0.93)
Weighted average common shares	15		
Basic		**557,048**	351,542
Diluted		**557,048**	351,542

See accompanying notes to the consolidated financial statements.

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

	Notes	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income	Deficit	Total equity
Balance at December 31, 2017		$ 4,443,576	$ 15,999	$ 463,104	$ (3,007,794)	**$ 1,914,885**
Issued on corporate acquisition	4	1,238,995	3,100	—	—	**1,242,095**
Issuance costs, net of tax	4, 13	(551)	—	—	—	**(551)**
Vesting of share awards	13	19,496	(19,496)	—	—	**—**
Share-based compensation	14	—	19,534	—	—	**19,534**
Comprehensive income (loss)		—	—	204,770	(325,309)	**(120,539)**
Balance at December 31, 2018		$ 5,701,516	$ 19,137	$ 667,874	$ (3,333,103)	**$ 3,055,424**
Vesting of share awards	13	17,319	(17,319)	—	—	**—**
Share-based compensation	14	—	15,894	—	—	**15,894**
Comprehensive loss		—	—	(111,650)	(12,459)	**(124,109)**
Balance at December 31, 2019		$ 5,718,835	$ 17,712	$ 556,224	$ (3,345,562)	**$ 2,947,209**

See accompanying notes to the consolidated financial statements.

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

Years Ended December 31	Notes	2019	2018
CASH PROVIDED BY (USED IN):			
Operating activities			
Net loss		$ **(12,459)**	$ (325,309)
Adjustments for:			
Share-based compensation	14	**15,894**	19,534
Unrealized foreign exchange (gain) loss	19	**(62,753)**	106,143
Exploration and evaluation	6	**11,764**	21,729
Depletion and depreciation	7, 8, 9	**731,686**	558,684
Impairment	6, 7	**187,822**	285,341
Non-cash financing and accretion	18	**18,448**	14,768
Unrealized financial derivatives loss (gain)	20	**82,817**	(116,715)
Gain on dispositions		**(2,238)**	(1,946)
Deferred income tax recovery	17	**(68,555)**	(101,732)
Payments on onerous contracts		**—**	(588)
Asset retirement obligations settled	12	**(15,417)**	(14,035)
Change in non-cash working capital	21	**(52,070)**	39,448
		834,939	485,322
Financing activities			
Decrease in bank loan	10	**(7,775)**	(21,295)
Common share issuance costs	13	**—**	(755)
Payments on lease obligations	9	**(5,956)**	—
Redemption of long-term notes	11	**(198,128)**	—
		(211,859)	(22,050)
Investing activities			
Additions to exploration and evaluation assets	6	**(2,948)**	(10,567)
Additions to oil and gas properties	7	**(549,343)**	(485,154)
Additions to other plant and equipment	8	**(552)**	(1,804)
Property acquisitions		**(3,667)**	(701)
Proceeds from dispositions		**1,487**	2,519
Change in non-cash working capital	21	**(62,485)**	32,435
		(617,508)	(463,272)
Change in cash		**5,572**	—
Cash, beginning of year		**—**	—
Cash, end of year		$ **5,572**	$ —
Supplementary information			
Interest paid		$ **112,241**	$ 104,821
Income taxes paid		$ **1,160**	$ —

See accompanying notes to the consolidated financial statements.

1. REPORTING ENTITY

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

2. BASIS OF PRESENTATION

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (the "IASB"). The significant accounting policies set forth below were consistently applied to all periods presented except for the adoption of IFRS 16 Leases as discussed in note 3.

The consolidated financial statements were approved by the Board of Directors of Baytex on March 3, 2020.

The consolidated financial statements have been prepared on a historical cost basis, with the exception of certain fair value measurements noted in the accounting policies set forth below. The consolidated financial statements are presented in Canadian dollars which is the presentation currency of the Company. References to “US$” are to United States ("U.S.") dollars. All financial information is rounded to the nearest thousand, except per share amounts or where otherwise indicated.

Measurement Uncertainty and Judgments

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.

3. SIGNIFICANT 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.

Significant accounting policies

Consolidation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies to obtain benefits from its activities. Significant subsidiaries included in the Company's accounts include Baytex Energy USA, Inc., Baytex Energy Ltd. and Baytex Energy Limited Partnership. Intercompany balances and transactions are eliminated in preparation of the consolidated financial statements.

Many of the Company's exploration, development and production activities are conducted through joint arrangements. The consolidated financial statements include the Company's proportionate share of the assets, liabilities, revenues and expenses generated by joint arrangements.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting when the acquired assets meet the definition of a business under IFRS. The cost of an acquisition is measured as cash paid and the fair value of assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. The acquired identifiable assets and liabilities assumed are measured at their fair values at the date of acquisition. Any excess of the cost of acquisition over the fair value of the net identifiable assets acquired is recognized as goodwill. If the cost of acquisition is below the fair values of the identifiable net assets acquired, the difference is recognized as a bargain purchase gain in net income or loss. Associated transaction costs are expensed when incurred.

Revenue Recognition

Revenue from the sale of light oil and condensate, heavy oil, natural gas liquids, and natural gas is recognized based on the consideration specified in contracts with customers. Baytex recognizes revenue by unit of production and when control of the product transfers to the customer and collection is reasonably assured. This is generally at the point in time when the customer obtains legal title to the product which is when it is physically transferred to the pipeline or other transportation method agreed upon.

The nature of the Company's performance obligations, including roles of third parties and partners, are evaluated to determine if the Company acts as a principal. Baytex recognizes revenue on a gross basis when it acts as the principal and has primary responsibility for the transaction. Revenue is recognized on a net basis when Baytex acts in the capacity of an agent rather than as a principal.

The transaction price for variable price contracts in the Canadian and U.S. operating segments is based on a representative commodity price index, and may include adjustments for quality, location, delivery method, or other factors depending on the agreed upon terms of the contract. The amount of revenue recorded can vary depending on the grade, quality and quantities of oil or natural gas transferred to customers. Market conditions, which impact the Company's ability to negotiate certain components of the transaction price, can also cause the amount of revenue recorded to fluctuate from period to period.

Tariffs, tolls and fees charged to other entities for the use of pipelines and facilities owned by Baytex are evaluated by management to determine if these originate from contracts with customers or from incidental or collaborative arrangements. Tariffs, tolls and fees charged to other entities that are from contracts with customers are recognized in revenue when the related services are provided.

Exploration and Evaluation Assets

Pre-license costs, including certain geological, geophysical and seismic expenditures, are incurred before the legal rights to explore a specific area have been obtained. These costs are charged to exploration expense in the period in which they are incurred.

Once the legal right to explore has been acquired, costs directly associated with an exploration program are capitalized as an intangible asset until results of the exploration program have been evaluated. Costs capitalized as E&E assets include costs of license acquisition, technical services and studies, seismic acquisition, exploration drilling and testing of initial production results.

E&E costs are subject to technical, commercial and management review to confirm the continued intent to develop or otherwise extract the underlying reserves. The technical feasibility and commercial viability of extracting petroleum and natural gas resources is dependent on the existence of economically recoverable reserves for the project. If the asset is determined not to be technically feasible or commercially viable the accumulated E&E costs associated with the exploration project are charged to E&E expense in the period the determination is made.

Upon determination of technical feasibility and commercial viability, as evidenced by the classification of proved or probable reserves and management's intention to develop the E&E asset, the accumulated costs associated with the exploration project are tested for impairment and transferred to oil and gas properties.

Oil and Gas Properties

Items of oil and gas properties are initially recorded at cost. The initial cost of oil and gas properties includes the costs to acquire developed or producing oil and gas properties, and to develop oil and gas properties, such as costs of completing geological and geophysical surveys, drilling development wells, and the costs to construct and install development infrastructure such as wellhead equipment and processing facilities.

Oil and gas properties includes costs related to planned major inspection, overhaul and turnaround activities to maintain items of oil and gas properties and benefit future years of operations. Replacements outside of a major inspection, overhaul or turnaround are recognized as oil and gas properties when it is probable the future economic benefits of the replacement will be realized by the Company. The carrying amount of any replaced or disposed item of oil and gas properties is derecognized. Repair and maintenance costs incurred for servicing an item of oil and gas properties is recorded as operating expense as incurred.

Depletion and Depreciation

The costs associated with an item of oil and gas properties are depleted on a unit-of-production basis by depletable area over proved plus probable reserves once commercial production has commenced. Future development costs required to bring those reserves into production are included in the depletable base. For purposes of the depletion calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of natural gas equates to one barrel of oil equivalent.

The depreciation methods and estimated useful lives for other plant and equipment are as follows:

Classification	Method	Rate or period
Motor Vehicles	Diminishing balance	15%
Office Equipment	Diminishing balance	20%
Computer Hardware	Diminishing balance	30%
Furniture and Fixtures	Diminishing balance	10%
Leasehold Improvements	Straight-line over life of the lease	Various
Other Assets	Diminishing balance	Various

The expected lives of other plant and equipment are reviewed on an annual basis and, if necessary, changes in expected useful lives are accounted for prospectively.

Impairment

Non-derivative financial assets

The Company assesses non-derivative financial assets at each reporting date to determine whether there is any objective evidence indicating that it is impaired. Objective evidence exists if one or more events have had a negative effect on the estimated future cash flows of that asset. An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows.

An impairment loss is reversed when there is objective evidence that the value of the financial assets has been partially or fully restored. For financial assets measured at amortized cost the reversal is recognized in net income or loss.

Non-financial assets

The Company reviews its non-financial assets, other than E&E assets, for indicators of impairment and impairment reversal at the end of each reporting period. The recoverable amount of the asset is estimated if indicators of impairment or impairment reversal exist. E&E assets are assessed for impairment when they are reclassified to oil and gas properties and if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

When reviewing for indicators of impairment and impairment reversal, and testing for impairment when indicators have been identified, assets are grouped together at a CGU level. The recoverable amount of an asset or CGU is the higher of its FVLCD and its VIU. The determination of recoverable amount includes estimates of proved and probable oil and gas reserves and the associated cash flows. Factors that impact these cash flows includes CGU production volumes, royalty obligations, operating costs, capital costs, forecast commodity prices, along with inflation and discount rates used to estimate present value. FVLCD is determined as the amount that would be obtained from the sale of an asset or CGU in an arm's length transaction between willing parties. In determining FVLCD, recent market transactions are considered if available. In the absence of such transactions, an appropriate valuation model is used. VIU is assessed using the present value of the estimated future cash flows of the asset or CGU. The estimated future cash flows are adjusted for risks specific to the asset or CGU and are discounted using a discount rate that reflects current market assessments of the time value of money.

Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount. The impairment reduces the carrying amount of any goodwill allocated to the CGU first, with any remaining impairment being allocated to the individual assets in the CGU on a pro-rata basis.

Impairments may be reversed for all CGUs and individual assets, other than goodwill, when there is indication that a previously recognized impairment may no longer exist or may have decreased. If such indication exists, the recoverable amount is estimated. An impairment may be reversed only to the extent that the asset's revised carrying amount does not exceed the carrying amount that would have been determined, net of depreciation and depletion, had no impairment been recognized. Impairment recognized in relation to goodwill is not reversed for subsequent increases in its recoverable amount.

Impairments and impairment reversals are recorded in net income or loss in the period the impairment or impairment reversal occurs.

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.

Asset Retirement Obligations

The Company recognizes asset retirement obligations when it has a legal or constructive obligation as a result of past events, it is probable that an outflow of economic resources will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. The Company's asset retirement obligations are based on its net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities using existing technology and the estimated time period during which these costs will be incurred in the future.

Asset retirement obligations are recognized for future asset retirement costs associated with the abandonment and reclamation of the Company's E&E assets and oil and gas properties. Asset retirement obligations are measured at the present value of management's best estimate of the future cash flows required to settle the present obligation, using the risk-free interest rate. The present value of the liability is capitalized as part of the cost of the related asset and depleted over its useful life. The asset retirement obligation is accreted until the date of expected settlement of the retirement obligation and is recognized within finance expense in the statements of income or loss. Changes in the future cash flow estimates resulting from revisions to the estimated timing or amount of undiscounted cash flows or the discount rates are recognized as changes in the asset retirement obligation provision and related asset at each reporting date.

Foreign Currency Translation

Foreign transactions

Transactions completed in currencies other than the functional currency are translated into the functional currency at the exchange rates prevailing at the time of the transactions. Foreign currency assets and liabilities are translated to functional currency at the period-end exchange rate. Revenue and expenses are translated to functional currency using the average exchange rate for the period. Realized and unrealized gains and losses resulting from the settlement or translation of foreign currency transactions are included in net income or loss.

Foreign operations

The functional currency of the Company's subsidiaries is the currency of the primary economic environment in which the entity operates. Certain subsidiaries of the Company operate and transact primarily in currencies other than the Canadian dollar. The designation of a subsidiary's functional currency is a management judgment based on the currency of the primary economic environment in which the subsidiary operates.

The financial statements of each entity are translated into Canadian dollars in preparation of the Company's consolidated financial statements. The assets and liabilities of a foreign operation are translated to Canadian dollars at the period-end exchange rate. Revenues and expenses of foreign operations are translated to Canadian dollars using the average exchange rate for the period. Foreign exchange differences are recognized in other comprehensive income or loss.

If the Company or any of its entities disposes of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the accumulated foreign currency translation gains or losses related to the foreign operation are recognized in net income or loss.

Financial Instruments

IFRS 9 contains three principal classification categories for initial classification of financial assets: measured at amortized cost; fair value through other comprehensive income ("FVOCI"); or fair value through profit or loss ("FVTPL"). Financial assets are categorized based on the Company's objective for the asset and the contractual cash flows. A financial asset is classified as amortized cost if the asset is held with the objective to collect contractual cash flows that are solely payments of principal and interest on principal amounts outstanding. A financial asset is classified as FVOCI if the asset is held with the objective to both collect contractual cash flows and sell the financial asset. All other financial assets are measured at FVTPL. Financial assets are assessed for impairment using an expected credit loss model. Trade and other receivables are classified and measured at amortized cost.

The measurement categories for each class of financial asset and financial liability is set forth in the following table.

Financial Instrument	Classification
Cash and cash equivalents	Amortized cost
Trade and other receivables	Amortized cost
Financial derivatives	Fair value through profit or loss
Trade and other payables	Amortized cost
Bank loan	Amortized cost
Long-term notes	Amortized cost
Lease obligations	Amortized cost

An embedded derivative is a component of a contract that modifies the cash flows of the contract. These hybrid contracts consist of a host contract and an embedded derivative. The embedded derivative is separated from the host contract and accounted for as a derivative unless the economic characteristics and risks of the embedded derivative are closely related to the host contract. The embedded derivatives are measured at FVTPL.

Debt issuance costs related to the amendment our bank loan or the issuance of long term notes are capitalized and amortized as financing costs over the term of the credit facilities or long term notes. For a financial asset or a financial liability carried at amortized cost, transaction costs directly attributable to acquiring or issuing the asset or liability are added to, or deducted from, the fair value on initial recognition and amortized through net income or loss over the term of the financial instrument. Transaction costs that are directly attributable to the acquisition or issue of a financial asset or a financial liability classified as FVTPL are expensed at inception of the contract.

The Company formally documents its risk management objectives and strategies to manage exposures to fluctuations in commodity prices, interest rates and foreign currency exchange rates. The risk management policy permits the use of certain derivative financial instruments, including swaps and collars, to manage these fluctuations. All transactions of this nature entered into by the Company are related to underlying financial instruments or future petroleum and natural gas production. These instruments are classified as FVTPL. The Company does not use financial derivatives for trading or speculative purposes. The Company has not designated its financial derivative contracts as effective accounting hedges, and therefore has not applied hedge accounting. As a result, the Company applies the fair value method of accounting for all derivative instruments by recording an asset or liability on the statements of financial position and recognizing changes in the fair value of the instrument in the statements of income or loss for the current period. The fair values of these instruments are based on quoted market prices or, in their absence, third-party market indications and forecasts. Attributable transaction costs are recognized in net income or loss when incurred.

The Company has accounted for its physical delivery sales contracts, which were entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts. As such, these contracts are not considered to be derivative financial instruments and have not been recorded at fair value on the statements of financial position. Settlements on these physical delivery sales contracts are recognized in revenue in the period the product is delivered to the sales point.

Impairment of financial assets is determined by calculating the expected credit loss ("ECL"). The Company measures an ECL allowance for trade and other receivables. The Company determines the ECL which is the probability of default events related to the financial asset by using historical realized bad debts and forward looking information. The carrying amounts of financial assets are reduced by the amount of the ECL through an allowance account and losses are recognized in the statement of income or loss.

Fair Value of Financial Instruments

Baytex classifies the fair value of financial instruments according to the following hierarchy based on the amount of observable inputs used to value the instruments:

- Level 1: Values based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities.
- Level 2: Values based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability.
- Level 3: Values based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement.

Income Taxes

Current and deferred income taxes are recognized in net income or loss, except when they relate to items that are recognized directly in equity, in which case the current and deferred taxes are also recognized directly in equity.

Current income taxes for the current and prior periods are measured at the amount expected to be recoverable from or payable to the taxation authorities based on the income tax rates enacted at the end of the reporting period. The Company recognizes the financial statement impact of a tax filing position when it is probable that the position will be sustained upon audit. The liability is measured based on an assessment of possible outcomes and their associated probabilities.

The Company follows the balance sheet asset and liability method of accounting for income taxes. Under this method, deferred income taxes are recorded for the effect of any temporary differences between the carrying amounts of assets and liabilities in the consolidated financial statements and the corresponding tax basis used in the computation of taxable income. Deferred income tax liabilities are generally recognized for all taxable temporary differences. Deferred income tax assets are recognized for all temporary differences deductible to the extent future recovery is probable. The carrying amount of deferred income tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be recovered. Deferred income taxes are calculated using enacted or substantively enacted tax rates. Deferred income tax balances are adjusted for any changes in the enacted or substantively enacted tax rates and the adjustment is recognized in the period that the rate change occurs.

Share-based Compensation Plans

The Company has a full-value award plan (the "Share Award Incentive Plan") pursuant to which restricted awards and performance awards (collectively, "share awards") may be granted to the directors, officers and employees of the Company and its subsidiaries. The maximum number of common shares issuable under the Share Award Incentive Plan (and any other long-term incentive plans of the Company) shall not at any time exceed 3.8% of the then-issued and outstanding common shares.

Each restricted award entitles the holder to be issued the number of common shares designated in the restricted award (plus dividend equivalents). Each performance award entitles the holder to be issued the number of common shares designated in the performance award (plus dividend equivalents) multiplied by a payout multiplier. Expenses related to the Share Award Incentive Plan are determined based on the fair value of the share awards on the grant date which is based on quoted market prices for the Company's common shares. Both restricted and performance awards are expensed over the vesting period using the graded vesting method. The payout multiplier is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. In the case of both restricted and performance awards, the number of common shares to be issued on the applicable issue date is adjusted to account for the payments of dividends from the grant date to the applicable issue date.

The Company assumed share awards and share options pursuant to a business combination in 2018 (note 4). The share options were valued at the closing date of the transaction utilizing a Black-Scholes pricing model to value the share options. The share awards were valued at fair value using the quoted market price of the Company's common shares on the closing date of the transaction. The share awards assumed consist of restricted share awards and performance share awards with a fixed multiplier of 1.0. Share-based compensation is expensed over the remaining vesting period and recognized as share-based compensation expense, with a corresponding increase to contributed surplus.

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4. BUSINESS COMBINATION

On August 22, 2018, Baytex completed a plan of arrangement whereby Baytex acquired, directly and indirectly, all of the issued and outstanding common shares of Raging River Exploration Inc. ("Raging River"), a publicly traded oil and gas producer with light oil producing properties in southwest Saskatchewan and Alberta.

The acquisition was accounted for as a business combination whereby the net assets acquired and liabilities assumed were recorded at fair value at the acquisition date. Consideration consisted of the issuance of 315.3 million Baytex common shares valued at approximately $1.2 billion (based on the closing price of Baytex's common shares of $3.93 on the Toronto Stock Exchange on August 22, 2018). The fair value of oil and gas properties acquired was determined using estimates of proved plus probable reserves evaluated at December 31, 2018 by an independent reserves evaluator and adjusted for operations between August 22, 2018 and the effective date of the reserve evaluation. Asset retirement obligations were determined using internal estimates of the timing and estimated costs associated with the abandonment and reclamation of the wells and facilities acquired using a market discount rate of 7.5%.The fair value of exploration and evaluation properties was estimated with reference to recent land sales in similar areas.

The total consideration paid and estimates of the fair value of the assets acquired and liabilities assumed as at the date of the acquisition are set forth in the table below.

Consideration		
Common shares issued	$	1,238,995
Share-based compensation(1)		3,100
Total consideration	**$**	**1,242,095**
Fair value of net assets acquired		
Exploration and evaluation assets	$	97,858
Oil and gas properties		1,748,368
Working capital deficiency excluding bank debt and financial derivatives		(46,773)
Financial derivatives		(5,548)
Bank debt(2)		(316,800)
Asset retirement obligations		(39,960)
Deferred income tax liability		(195,050)
Net assets acquired	**$**	**1,242,095**

(1) Following closing of the transaction, holders of units outstanding under Raging River's share-based compensation plans were entitled to Baytex common shares rather than Raging River common shares with adjustment to the exercise price or quantity outstanding based on the exchange ratio for the Raging River shares. As a result, the fair value assigned to the service period that had occurred prior to closing was recognized by Baytex as additional consideration (see note 14).

(2) *On August 22, 2018, Baytex amended its credit facilities to include the credit facility assumed in conjunction with the acquisition of Raging River and converted outstanding principal amounts to a non-revolving term loan.*

The acquisition contributed revenue of $158.8 million and operating income of $98.6 million for the period from the acquisition date of August 22, 2018 to December 31, 2018. Had the acquisition occurred on January 1, 2018, revenue would have increased by $379.5 million and operating income would have increased by $273.2 million for the year. Operating income is defined as revenue, net of royalties, less operating, transportation and blending expense.

In 2018, transaction costs of $13.1 million were expensed as incurred and share issuance costs of $0.6 million (net of taxes of $0.2 million) were recorded in shareholders' capital in the year.

5. SEGMENTED FINANCIAL INFORMATION

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

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

	Canada		U.S.		Corporate		Consolidated	
Years Ended December 31	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 1,077,724**	$ 619,215	**$ 728,195**	$ 809,655	**$ —**	$ —	**$ 1,805,919**	$ 1,428,870
Royalties	**(107,467)**	(72,700)	**(212,774)**	(241,054)	**—**	—	**(320,241)**	(313,754)
	970,257	546,515	**515,421**	568,601	**—**	—	**1,485,678**	1,115,116
Expenses								
Operating	**298,303**	221,717	**99,413**	89,875	**—**	—	**397,716**	311,592
Transportation	**43,942**	36,869	**—**	—	**—**	—	**43,942**	36,869
Blending and other	**68,795**	68,832	**—**	—	**—**	—	**68,795**	68,832
General and administrative	**—**	—	**—**	—	**45,469**	45,825	**45,469**	45,825
Transaction costs	**—**	—	**—**	—	**—**	13,074	**—**	13,074
Exploration and evaluation	**11,764**	10,580	**—**	11,149	**—**	—	**11,764**	21,729
Depletion and depreciation	**463,501**	294,925	**261,766**	261,709	**6,419**	2,050	**731,686**	558,684
Impairment	**187,822**	65,000	**—**	220,341	**—**	—	**187,822**	285,341
Share-based compensation	**—**	—	**—**	—	**15,894**	19,534	**15,894**	19,534
Financing and interest	**—**	—	**—**	—	**125,865**	119,086	**125,865**	119,086
Financial derivatives loss (gain)	**—**	—	**—**	—	**7,197**	(43,550)	**7,197**	(43,550)
Foreign exchange (gain) loss	**—**	—	**—**	—	**(61,787)**	108,294	**(61,787)**	108,294
Gain on dispositions	**(2,238)**	(1,946)	**—**	—	**—**	—	**(2,238)**	(1,946)
Other income	**—**	—	**—**	—	**(7,526)**	(1,172)	**(7,526)**	(1,172)
	1,071,889	695,977	**361,179**	583,074	**131,531**	263,141	**1,564,599**	1,542,192
Net income (loss) before income taxes	**(101,632)**	(149,462)	**154,242**	(14,473)	**(131,531)**	(263,141)	**(78,921)**	(427,076)
Income tax expense (recovery)								
Current income tax expense (recovery)	**101**	—	**1,992**	(35)	**—**	—	**2,093**	(35)
Deferred income tax expense (recovery)	**(32,942)**	(40,723)	**10,055**	(26,049)	**(45,668)**	(34,960)	**(68,555)**	(101,732)
	(32,841)	(40,723)	**12,047**	(26,084)	**(45,668)**	(34,960)	**(66,462)**	(101,767)
Net income (loss)	**$ (68,791)**	$ (108,739)	**$ 142,195**	$ 11,611	**$ (85,863)**	$ (228,181)	**$ (12,459)**	$ (325,309)
Total oil and natural gas capital expenditures[(1)]	**$ 376,543**	$ 300,299	**$ 177,928**	$ 193,604	**$ —**	$ —	**$ 554,471**	$ 493,903

(1) Includes acquisitions, net of proceeds from divestitures.

As at	**December 31, 2019**	December 31, 2018
Canadian assets	**$ 3,484,123**	$ 3,739,029
U.S. assets	**2,403,310**	2,628,941
Corporate assets	**26,650**	9,228
Total consolidated assets	**$ 5,914,083**	$ 6,377,198

6. EXPLORATION AND EVALUATION ASSETS

	December 31, 2019	December 31, 2018
Balance, beginning of year	**$ 358,935**	$ 272,974
Capital expenditures	**2,948**	10,567
Corporate acquisition (note 4)	**—**	97,858
Property acquisitions	**1,523**	514
Divestitures	**(443)**	(1,021)
Impairment	**(7,822)**	—
Property swaps	**417**	—
Exploration and evaluation expense	**(11,764)**	(21,729)
Transfers to oil and gas properties (note 7)	**(16,204)**	(13,866)
Foreign currency translation	**(7,380)**	13,638
Balance, end of year	**$ 320,210**	$ 358,935

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

At December 31, 2018 the Company identified indicators of impairment for the exploration and evaluation assets within the Conventional CGU. The estimated recoverable amount exceeded the carrying value of the of the exploration and evaluation assets in the Conventional CGU and no impairment was recorded. There were no indicators of impairment for exploration and evaluation assets in the remaining CGUs at December 31, 2018.

7. OIL AND GAS PROPERTIES

	Cost	Accumulated depletion	Net book value
Balance, December 31, 2017	**$ 7,932,327**	**$ (3,974,018)**	**$ 3,958,309**
Capital expenditures	485,154	—	485,154
Corporate acquisition (note 4)	1,748,368	—	1,748,368
Property acquisitions	202	—	202
Transfers from exploration and evaluation assets (note 6)	13,866	—	13,866
Change in asset retirement obligations (note 12)	238,662	—	238,662
Divestitures	(15)	—	(15)
Impairment	—	(285,341)	(285,341)
Foreign currency translation	325,969	(110,651)	215,318
Depletion	—	(556,634)	(556,634)
Balance, December 31, 2018	**$ 10,744,533**	**$ (4,926,644)**	**$ 5,817,889**
Capital expenditures	549,343	—	549,343
Property acquisitions	2,636	—	2,636
Transfers from exploration and evaluation assets (note 6)	16,204	—	16,204
Change in asset retirement obligations (note 12)	23,894	—	23,894
Divestitures	(2,069)	1,690	(379)
Property swaps	1,773	—	1,773
Impairment	—	(180,000)	(180,000)
Foreign currency translation	(208,017)	89,813	(118,204)
Depletion	—	(725,267)	(725,267)
Balance, December 31, 2019	**$ 11,128,297**	**$ (5,740,408)**	**$ 5,387,889**

Baytex recorded impairment expense related to oil and gas properties of $180.0 million for the year ended December 31, 2019 and $285.3 million for the year ended December 31, 2018.

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

The recoverable amount of the Peace River CGU was calculated at December 31, 2019 using the following benchmark reference prices for the years 2020 to 2029 adjusted for commodity differentials specific to the Company.

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
WTI crude oil (US$/bbl)	61.00	63.75	66.18	67.91	69.48	71.07	72.68	74.24	75.73	77.24
WCS heavy oil (CA$/bbl)	57.57	62.35	64.33	66.23	67.97	69.72	71.49	73.20	74.80	76.43
AECO (CA$/GJ)	2.04	2.32	2.62	2.71	2.81	2.89	2.96	3.03	3.09	3.16
Exchange rate (CAD/USD)	1.32	1.30	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27

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

The following table demonstrates the sensitivity of the estimated recoverable amount of the Peace River CGU to reasonably possible changes in key assumptions inherent in the estimate.

	Change in discount rate of 1%	Change in oil price of $2.50/bbl
Change in impairment expense	$ 24,000	$ 88,000

At December 31, 2018, indicators of impairment existed for the Conventional CGU due to a sustained decline in Canadian natural gas prices and a reduction in planned capital exploration and development expenditures. The recoverable amount was not sufficient to support the carrying amount of the CGU which resulted in an impairment of $65.0 million recorded as at December 31, 2018. The recoverable amount of the Conventional CGU was based on its VIU which was estimated using a discounted cash flow model based on an independent reserve report approved by the Board of Directors and a range of pre-tax discount rates between 8% and 20%.

At December 31, 2018, indicators of impairment existed for the Eagle Ford CGU due to the expected development plan outlined by the operator which resulted in a decline in the net present value of the cash flows of the proved plus probable reserves. The recoverable amount was not sufficient to support the carrying amount of the CGU which resulted in an impairment of $220.3 million recorded as at December 31, 2018. The recoverable amount of the Eagle Ford CGU was based on its VIU which was estimated using a discounted cash flow model based on an independent reserve report approved by the Board of Directors and a range of pre-tax discount rates between 8% and 20%.

8. OTHER PLANT AND EQUIPMENT

	Cost	Accumulated depreciation	Net book value
Balance, December 31, 2017	**$ 62,648**	**$ (53,174)**	**$ 9,474**
Capital expenditures	1,804	—	1,804
Depreciation	—	(2,050)	(2,050)
Balance, December 31, 2018	**$ 64,452**	**$ (55,224)**	**$ 9,228**
Capital expenditures	552	—	552
Depreciation	—	(2,182)	(2,182)
Balance, December 31, 2019	**$ 65,004**	**$ (57,406)**	**$ 7,598**

9. LEASES

Lease Assets

Baytex had the following right-of-use assets at December 31, 2019.

	Office Leases	Field Equipment	Vehicles and Other	Total
Balance, January 1, 2019 [1]	**$ 14,775**	**$ 2,254**	**$ 969**	**$ 17,998**
Additions	—	1,668	159	1,827
Modifications	(6)	4	19	17
Depreciation	(4,904)	(837)	(482)	(6,223)
Balance, December 31, 2019	**$ 9,865**	**$ 3,089**	**$ 665**	**$ 13,619**

(1) The Company adopted IFRS 16 Leases on January 1, 2019 using the modified retrospective approach. At December 31, 2018, the Company did not report any finance leases in accordance with its previous accounting policy for leases.

Lease Obligations

Baytex had the following future commitments associated with its lease obligations at December 31, 2019.

	December 31, 2019
Less than 1 year	**$ 6,216**
1 - 3 years	**7,748**
3 - 5 years	**604**
After 5 years	**—**
Total lease payments	**$ 14,568**
Amounts representing interest over the term of the lease	**(685)**
Present value of net lease payments	**$ 13,883**
Less current portion of lease obligations	**5,798**
Non-current portion of lease obligations	**$ 8,085**

The Company recorded interest expense related to its lease obligations of $0.6 million and recorded lease payments of $6.0 million for the year ended December 31, 2019.

10. BANK LOAN

	December 31, 2019	December 31, 2018
Bank loan - U.S. dollar denominated[1]	**$ 206,144**	$ 122,388
Bank loan - Canadian dollar denominated	**300,327**	399,906
Bank loan - principal[2]	**$ 506,471**	$ 522,294
Unamortized debt issuance costs	**(1,059)**	(1,594)
Bank loan	**$ 505,412**	$ 520,700

(1) U.S. dollar denominated bank loan balance was US$159.0 million as at December 31, 2019 (US$89.7 million as at December 31, 2018).
(2) The decrease in the principal amount of the bank loan outstanding from December 31, 2018 to December 31, 2019 is the result of loan repayments of $7.1 million and changes in the reported amount of U.S. denominated debt of $8.7 million.

Baytex has US$575 million of revolving secured credit facilities (the "Revolving Facilities") and a CAD$300 million non-revolving secured term loan (the "Term Loan"). On May 2, 2019, Baytex amended its credit facilities to extend maturity from June 4, 2020 to April 2, 2021. On March 3, 2020, Baytex amended its credit facilities to extend maturity to April 2, 2024. These facilities will automatically be extended to June 4, 2024 providing Baytex has either refinanced or has the ability to repay the outstanding 2024 long-term notes with existing credit capacity as of April 1, 2024.

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

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

At December 31, 2019, Baytex had $15.2 million of outstanding letters of credit under the credit facilities (December 31, 2018 - $14.6 million).

At December 31, 2019, Baytex was in compliance with all of the covenants contained in the credit facilities. The following table summarizes the financial covenants applicable to the Revolving 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.

11. LONG-TERM NOTES

		December 31, 2019		December 31, 2018
6.75% notes (US$150,000 – principal) due February 17, 2021	**$**	**—**	$	204,683
5.125% notes (US$400,000 – principal) due June 1, 2021		**518,600**		545,820
6.625% notes (Cdn$300,000 – principal) due July 19, 2022		**300,000**		300,000
5.625% notes (US$400,000 – principal) due June 1, 2024		**518,600**		545,820
Total long-term notes - principal[1]	**$**	**1,337,200**	$	1,596,323
Unamortized debt issuance costs		**(9,025)**		(13,083)
Total long-term notes - net of unamortized debt issuance costs	**$**	**1,328,175**	$	1,583,240

(1) The decrease in the principal amount of long-term notes outstanding from December 31, 2018 to December 31, 2019 is the result of principal repayments of $198.1 million and changes in the reported amount of U.S. denominated debt of $61.0 million.

On September 13, 2019, Baytex completed the early redemption of the US$150,000 principal amount of 6.75% senior unsecured notes, due February 17, 2021. The total principal payment was $198.1 million.

The long-term notes do not contain any significant financial maintenance covenants. The long-term notes contain a debt incurrence covenant that restricts the Company's ability to raise additional debt beyond the existing credit facilities and long-term notes unless the Company maintains a minimum coverage ratio (computed as the ratio of Bank EBITDA (as defined in note 10) 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, Baytex issued US$500 million aggregate principal amount of senior unsecured notes due April 1, 2027 bearing interest at a rate of 8.75% per annum payable semi-annually in arrears (the "8.75% Senior Notes"). The 8.75% Senior Notes are redeemable at our option, in whole or in part, at specified redemption prices after April 1, 2023 and will be redeemable at par from April 1, 2026 to maturity. Transaction costs of $12.4 million were incurred in conjunction with the issuance which resulted in net proceeds of $652.3 million.

On February 20, 2020, Baytex used a portion of the net proceeds from the issuance of the 8.75% Senior Notes of $652.3 million to complete the early redemption of the US$400 million principal amount of the 5.125% senior unsecured notes due June 1, 2021 at par plus accrued interest. On February 5, 2020, the Company also issued a notice of redemption for the $300 million principal amount of our 6.625% senior unsecured notes due July 19, 2022. Baytex expects to complete the early redemption of these notes on March 6, 2020 at 101.104% of the principal amount plus accrued interest.

12. ASSET RETIREMENT OBLIGATIONS

		December 31, 2019		December 31, 2018
Balance, beginning of year	**$**	**646,898**	$	368,995
Liabilities incurred		**21,748**		12,537
Liabilities settled		**(15,417)**		(14,035)
Liabilities assumed from corporate acquisition (note 4)		**—**		39,960
Liabilities acquired from property acquisitions		**1,648**		132
Liabilities divested		**(1,331)**		(580)
Property swaps		**792**		—
Accretion (note 18)		**13,713**		10,914
Change in estimate[(1)]		**19,632**		33,453
Changes in discount rates and inflation rates		**(17,486)**		192,672
Foreign currency translation		**(2,223)**		2,850
Balance, end of year	**$**	**667,974**	$	646,898
Less current portion of asset retirement obligations		**11,579**		—
Non-current portion of asset retirement obligations	**$**	**656,395**	$	646,898

(1) Changes in the estimated costs, the timing of abandonment and reclamation and the status of wells are factors resulting in a change in estimate.

At December 31, 2019, the undiscounted amount of estimated cash flows required to settle the asset retirement obligations is $714.8 million (December 31, 2018 - $673.1 million). The discounted amount of estimated cash flow required to settle the asset retirement obligations at December 31, 2019 calculated using an estimated inflation rate of 1.4% (December 31, 2018 - 2.0%) and a risk free rate discount rate of 1.8% (December 31, 2018 - 2.2%) is $668.0 million (December 31, 2018 - $646.9 million). These costs are expected to be incurred over the next 60 years.

13. SHAREHOLDERS' CAPITAL

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10.0 million preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. As at December 31, 2019, no preferred shares have been issued by the Company and all common shares issued were fully paid.

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

	Number of Common Shares *(000s)*		Amount
Balance, December 31, 2017	**235,451**	**$**	**4,443,576**
Vesting of share awards	3,343		19,496
Issued on corporate acquisition (note 4)	315,266		1,238,995
Issuance costs, net of tax (note 4)	—		(551)
Balance, December 31, 2018	**554,060**	**$**	**5,701,516**
Vesting of share awards	4,245		17,319
Balance, December 31, 2019	**558,305**	**$**	**5,718,835**

14. SHARE-BASED COMPENSATION PLAN

The Company recorded compensation expense related to the share awards and share options of $15.9 million for the year ended December 31, 2019 ($19.5 million for the year ended December 31, 2018).

Share Awards

The weighted average fair value of share awards granted during the year ended December 31, 2019 was $2.63 per restricted and performance award (December 31, 2018 - $4.04).

The number of share awards outstanding is detailed below:

(000s)	Number of restricted awards	Number of performance awards[1]	Total number of share awards
Balance, December 31, 2017	**2,028**	**2,253**	**4,281**
Granted	2,793	2,591	5,384
Assumed on corporate acquisition [2]	302	257	559
Vested and converted to common shares	(1,682)	(1,661)	(3,343)
Forfeited	(198)	(167)	(365)
Balance, December 31, 2018	**3,243**	**3,273**	**6,516**
Granted	3,184	3,245	6,429
Vested and converted to common shares	(2,081)	(2,164)	(4,245)
Forfeited	(545)	(1,219)	(1,764)
Balance, December 31, 2019	**3,801**	**3,135**	**6,936**

(1) Based on underlying awards before applying the payout multiplier which can range from 0x to 2x.
(2) Following closing of the business combination (note 4), holders of 0.3 million Raging River restricted awards and 0.3 million performance awards are entitled to receive Baytex common shares rather than Raging River common shares, after adjusting the quantity of awards outstanding based on the exchange ratio. The payout multiplier for the performance awards is fixed at 1.0. The fair value assigned to the service period that had occurred prior to closing was included in consideration for the business combination.

Share Options

Baytex assumed share option plans pursuant to a business combination in 2018 (note 4). No new grants will be made under the option plans.

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

One third of the options granted will vest on each of the first, second, and third anniversaries of the date of grant. At December 31, 2019, 2.5 million share options with a weighted average exercise price of $6.83 were outstanding. The following tables summarize the information about the share options.

(000s, except per common share amounts)	Number of options	Weighted average exercise price
Balance, December 31, 2017	**—**	**$ —**
Assumed on corporate acquisition	9,187	6.63
Forfeited/Expired	(4,322)	6.57
Balance, December 31, 2018	**4,865**	**$ 6.70**
Forfeited/Expired	(2,390)	6.56
Balance, December 31, 2019	**2,475**	**$ 6.83**

	Options Outstanding			Options Exercisable	
Exercise price	Number outstanding at December 31, 2019 (000s)	Weighted average remaining life (years)	Weighted average exercise price	Number exercisable at December 31, 2019 (000s)	Weighted average exercise price
$5.00 - $7.00	1,654	0.79	$ 6.39	1,248	$ 6.42
$7.01 - $9.00	821	0.15	7.73	821	7.73
Total	**2,475**	**0.58**	**$ 6.83**	**2,069**	**$ 6.94**

15. NET INCOME (LOSS) PER SHARE

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

	Years Ended December 31					
	2019			2018		
	Net loss	**Weighted average common shares (000's)**	**Net loss per share**	Net loss	Weighted average common shares (000's)	Net loss per share
Net loss - basic	**$ (12,459)**	**557,048**	**$ (0.02)**	$ (325,309)	351,542	$ (0.93)
Dilutive effect of share awards	**—**	**—**	**—**	—	—	—
Dilutive effect of share options	**—**	**—**	**—**	—	—	—
Net loss - diluted	**$ (12,459)**	**557,048**	**$ (0.02)**	$ (325,309)	351,542	$ (0.93)

For the year ended December 31, 2019, 6.9 million share awards (2018 - 6.5 million) and 2.5 million share options (2018 - 4.9 million) were excluded from the calculation of diluted earnings per share as the Company recorded a net loss.

16. PETROLEUM AND NATURAL GAS SALES

The Company's petroleum and natural gas sales from contracts with customers for each reportable segment is set forth in the following table.

	Years Ended December 31					
	2019			2018		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
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
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

Included in accounts receivable at December 31, 2019 is $138.0 million (December 31, 2018 - $77.4 million) of accrued petroleum and natural gas sales related to deliveries for periods ended prior to the reporting date.

17. INCOME TAXES

The provision for income taxes has been computed as follows:

	Years Ended December 31	
	2019	2018
Net loss before income taxes	**$ (78,921)**	$ (427,076)
Expected income taxes at the statutory rate of 26.72% (2018 – 27.00%)	**(21,088)**	(115,311)
(Increase) decrease in income tax recovery resulting from:		
Share-based compensation	**4,247**	5,185
Non-taxable portion of foreign exchange (gain) loss	**(8,155)**	14,467
Effect of change in income tax rates	**(6,098)**	—
Effect of rate adjustments for foreign jurisdictions	**(27,785)**	(22,119)
Effect of change in deferred tax benefit not recognized(1)	**(7,563)**	14,467
Adjustments and assessments	**(20)**	1,544
Income tax recovery	**$ (66,462)**	$ (101,767)

(1) A deferred income tax asset has not been recognized for accumulated allowable capital losses of $109 million ($139 million as at December 31, 2018) related to the foreign exchange losses arising from the translation of U.S. dollar denominated long-term notes.

For the year ended December 31, 2019, the deferred tax recovery includes $6.1 million attributable to decreases in the Alberta provincial income tax rate for the period from July 1, 2019 to January 1, 2022, which reduced the provincial tax rate to 11% effective July 1, 2019, and further reduces it by 1% on January 1st for each of the years 2020, 2021, and 2022, resulting in a provincial rate of 8%.

In June 2016, certain indirect subsidiary entities 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, Baytex filed notices of objection with the CRA appealing each reassessment received. There has been no change in the status of these reassessments since an Appeals Office was assigned to the Company's file in July 2018. Baytex remains confident that the original tax filings are correct and intends to defend these tax filings through the appeals process.

A continuity of the net deferred income tax liability is detailed in the following tables:

As at	January 1, 2019	Recognized in Net Income	Foreign Currency Translation Adjustment	**December 31, 2019**
Taxable temporary differences:				
Petroleum and natural gas properties	$ (954,506)	$ 48,995	$ 23,517	**$ (881,994)**
Financial derivatives	(21,486)	21,486	—	**—**
Other	(3,045)	5,192	(4,550)	**(2,403)**
Deductible temporary differences:				
Asset retirement obligations	172,359	(7,364)	(472)	**164,523**
Financial derivatives	—	802	—	**802**
Non-capital losses	399,699	(1,460)	(11,522)	**386,717**
Finance costs	96,143	904	—	**97,047**
Net deferred income tax liability(1)	$ (310,836)	$ 68,555	$ 6,973	**$ (235,308)**

(1) Non-capital loss carry-forwards at December 31, 2019 totaled $1,714.6 million and expire from 2029 to 2039.

As at	January 1, 2018	Recognized in Net Loss	Share Issuance Costs	Business Combination	Foreign Currency Translation Adjustment	**December 31, 2018**
Taxable temporary differences:						
Petroleum and natural gas properties	$ (696,427)	$ (11,639)	$ —	$ (207,337)	$ (39,103)	**$ (954,506)**
Financial derivatives	—	(22,984)	—	1,498	—	**(21,486)**
Deferred income	(17,827)	17,827	—	—	—	**—**
Other	(5,956)	(2,538)	209	—	5,240	**(3,045)**
Deductible temporary differences:						
Asset retirement obligations	97,977	62,984	—	10,789	609	**172,359**
Financial derivatives	8,528	(8,528)	—	—	—	**—**
Non-capital losses	330,749	48,725	—	—	20,225	**399,699**
Finance costs	78,258	17,885	—	—	—	**96,143**
Net deferred income tax liability[1]	$ (204,698)	$ 101,732	$ 209	$ (195,050)	$ (13,029)	**$ (310,836)**

(1) Non-capital loss carry-forwards at December 31, 2018 totaled $1,733.8 million and expire from 2029 to 2038.

18. FINANCING AND INTEREST

	Years Ended December 31	
	2019	2018
Interest on bank loan	**$ 20,376**	$ 15,637
Interest on long-term notes	**86,431**	88,681
Interest on lease obligations	**610**	—
Non-cash financing	**4,735**	3,854
Accretion of asset retirement obligations (note 12)	**13,713**	10,914
Financing and interest	**$ 125,865**	$ 119,086

19. FOREIGN EXCHANGE

	Years Ended December 31	
	2019	2018
Unrealized foreign exchange (gain) loss	**$ (62,753)**	$ 106,143
Realized foreign exchange loss	**966**	2,151
Foreign exchange (gain) loss	**$ (61,787)**	$ 108,294

20. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

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

	December 31, 2019		December 31, 2018		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL					
Financial Derivatives	**$ 5,433**	**$ 5,433**	$ 79,582	$ 79,582	Level 2
Total	**$ 5,433**	**$ 5,433**	$ 79,582	$ 79,582	
Financial assets at amortized cost					
Cash	**$ 5,572**	**$ 5,572**	$ —	$ —	—
Trade and other receivables	**173,762**	**173,762**	111,564	111,564	—
Total	**$ 179,334**	**$ 179,334**	$ 111,564	$ 111,564	
Financial Liabilities					
FVTPL					
Financial Derivatives	**$ (8,668)**	**$ (8,668)**	$ —	$ —	Level 2
Total	**$ (8,668)**	**$ (8,668)**	$ —	$ —	
Financial liabilities at amortized cost					
Trade and other payables	**$ (207,454)**	**$ (207,454)**	$ (258,114)	$ (258,114)	—
Bank loan	**(505,412)**	**(506,471)**	(520,700)	(522,294)	—
Long-term notes	**(1,328,175)**	**(1,290,817)**	(1,583,240)	(1,492,363)	Level 1
Lease obligations	**(13,883)**	**(13,883)**	—	—	—
Total	**$ (2,054,924)**	**$ (2,018,625)**	$ (2,362,054)	$ (2,272,771)	

There were no transfers of financial instruments between Level 1 and Level 2 in during the years ended December 31, 2019 or 2018.

Financial Risk

Baytex is exposed to a variety of financial risks, including market risk, liquidity risk and credit risk. The Company's process to mitigate these risks is described below.

Market Risk

Market risk is the risk that the fair value or future cash flows of financial assets or liabilities will fluctuate due to movements in market prices. Market risk is comprised of foreign currency risk, interest rate risk and commodity price risk.

Foreign Currency Risk

Baytex is exposed to fluctuations in foreign exchange rates as a result of the U.S. dollar portion of its bank loan and long-term notes, crude oil sales based on U.S. dollar benchmark prices and commodity financial derivative contracts that are settled in U.S. dollars. The Company's net income or loss, comprehensive income or loss and cash flow will therefore be impacted by fluctuations in foreign exchange rates.

To manage the impact of foreign exchange rate fluctuations, the Company may enter into agreements to fix the Canadian to U.S. dollar exchange rate. At December 31, 2019 and 2018, the Company did not have any currency derivative contracts outstanding.

A $0.01 increase or decrease in the CAD/USD foreign exchange rate on the revaluation of outstanding U.S. dollar denominated assets and liabilities, would impact net income or loss before income taxes by approximately $8.3 million.

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

	Assets		Liabilities	
	December 31, 2019	December 31, 2018	**December 31, 2019**	December 31, 2018
U.S. dollar denominated	**US$8,733**	US$80,857	**US$841,961**	US$963,351

Interest Rate Risk

The Company's interest rate risk arises from borrowing at floating rates under the Revolving Facilities and Term Loan (note 10). Based on the Company's principal bank loan outstanding net of the interest rate swap, as at December 31, 2019, a change of 100 basis points in interest rates would have an impact on net income or loss before income taxes of approximately $4.1 million.

Interest Rate Swaps

The Company mitigates its exposure to interest rate risk by entering into interest rate swap transactions. As of March 3, 2020, Baytex had an interest rate swap outstanding with a notional value of $100 million maturing in October 2020, with a fixed contract price of 2.02% referencing the Canadian Dollar Offered Rate. At December 31, 2019, the interest rate swap had a fair value of zero (December 31, 2018 - $0.3 million).

Commodity Price Risk

Baytex utilizes financial derivative contracts or physical delivery contracts to manage the risk associated with changes in commodity prices. The use of derivatives is governed by a Risk Management Policy approved by the Board of Directors of Baytex which sets out limits on the use of derivatives. Baytex does not use financial derivatives for speculative purposes. Baytex's financial derivative contracts are subject to master netting agreements that create a legally enforceable right to offset by the counterparty the related financial assets and financial liabilities.

When assessing the potential impact of crude oil price changes on the crude oil financial derivative contracts outstanding as at December 31, 2019, a US$1.00/bbl change in the underlying benchmark crude oil prices would impact net income or loss before income taxes by approximately $17.5 million.

When assessing the potential impact of natural gas price changes on the financial derivative contracts outstanding as at December 31, 2019, a $0.25 change in the underlying benchmark natural gas prices would impact net income or loss before income taxes by approximately $1.2 million.

Financial Derivative Contracts

Baytex had the following financial derivative contracts outstanding as of 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 US50 /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.

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

	Years Ended December 31	
	2019	2018
Realized financial derivatives (gain) loss	**$ (75,620)**	$ 73,165
Unrealized financial derivatives loss (gain)	**82,817**	(116,715)
Financial derivatives loss (gain)	**$ 7,197**	$ (43,550)

Liquidity Risk

Liquidity risk is the risk that Baytex will encounter difficulty in meeting obligations associated with financial liabilities. Baytex manages its liquidity risk through cash and debt management. Such strategies include monitoring forecasted and actual cash flows from operating, financing and investing activities, available credit under existing banking arrangements, opportunities to issue additional common shares as well as reducing capital expenditures. As at December 31, 2019, Baytex had available unused bank credit facilities in the amount of $523.8 million (December 31, 2018 - $547.7 million). In the event the Company is not able to comply with the financial covenants contained in agreements with its lenders, the Company's ability to access additional debt may be restricted.

The timing of cash outflows relating to financial liabilities as at December 31, 2019 is outlined in the table below:

	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	—
	$ 2,282,940	**$ 289,295**	**$ 1,433,122**	**$ 560,523**	**$ —**

(1) At December 31, 2019, the bank loan was set to mature on April 2, 2021. On March 3, 2020, Baytex amended the bank loan to extend maturity to April 2, 2024 which will automatically be extended to June 4, 2024 providing the Company has either refinanced or has the ability to repay the outstanding 2024 long-term notes with existing credit capacity as of April 1, 2024.

(2) Principal amount of instruments. On February 5, 2020, Baytex issued US$500 million principal amount of 8.75% senior unsecured notes due 2027 and issued a redemption notice for the $300 million principal amount of 6.625% senior unsecured notes due 2022 (note 11). The Company expects to complete the redemption of these notes on March 6, 2020. On February 20, 2020 Baytex completed the redemption of the US$400 million principal amount of senior unsecured notes due 2021 (note 11).

(3) Excludes interest on bank loan as interest payments on bank loans fluctuate based on amounts outstanding and interest rates.

Credit Risk

Credit risk is the risk that a counterparty to a financial asset will default resulting in Baytex incurring a loss. As at December 31, 2019, the Company is exposed to credit risk with respect to its trade and other receivables and financial derivatives.

Credit risk is considered very low for the Company's trade and other receivables and financial derivatives due to the external credit ratings of its counterparties and Baytex's process for selecting and monitoring credit-worthy counterparties. Most of the Company's trade and other receivables relate to petroleum and natural gas sales and are exposed to typical industry credit risks. Baytex reviews its exposure to individual entities on a regular basis and manages its credit risk by entering into sales contracts with only creditworthy entities. Letters of credit or parental guarantees may be obtained prior to the commencement of business with certain counterparties. Credit risk may also arise from financial derivative instruments. The maximum exposure to credit risk is equal to the carrying value of the financial assets. The Company considers all financial assets that are not impaired or past due to be of good credit quality.

The majority of the Company's credit exposure on accounts receivable at December 31, 2019 relates to accrued revenues for November and December 2019. Accounts receivable from purchasers of the Company's petroleum and natural gas sales are typically collected on the 25th day of the month following production. Joint interest receivables are typically collected within one to three months following production. Included in accounts receivable at December 31, 2019 is $138.0 million (December 31, 2018 - $77.4 million) of accrued petroleum and natural gas sales related to deliveries for periods ended prior to the reporting date.

Should the Company determine that the ultimate collection of a receivable is in doubt, the carrying amount of accounts receivable is reduced by the use of an allowance for doubtful accounts and a charge to net income or loss. If the Company subsequently determines the accounts receivable is uncollectible, the receivable and allowance for doubtful accounts are adjusted accordingly. As at December 31, 2019, allowance for doubtful accounts was $1.6 million (December 31, 2018 - $1.9 million).

In determining whether amounts past due are collectible, the Company will assess the nature of the past due amounts as well as the credit worthiness and past payment history of the counterparty. As at December 31, 2019, accounts receivable that Baytex has deemed past due (more than 90 days) but not impaired was $2.7 million (December 31, 2018 - $2.6 million). Baytex has estimated the lifetime expected credit loss as at and for the years ended December 31, 2019 to be nominal.

The Company's trade and other receivables, net of the allowance for doubtful accounts, were aged as follows at December 31, 2019.

Trade and Other Receivables Aging	December 31, 2019	December 31, 2018
Current (less than 30 days)	$ 169,500	$ 104,099
31-60 days	1,199	3,037
61-90 days	342	1,842
Past due (more than 90 days)	2,721	2,586
	$ 173,762	$ 111,564

21. SUPPLEMENTAL INFORMATION

Change in Non-Cash Working Capital Items

	Years Ended December 31	
	2019	2018
Trade and other receivables	$ (62,198)	$ 1,280
Trade and other payables	(50,660)	113,572
Non-cash working capital acquired (note 4)	—	(46,773)
	$ (112,858)	$ 68,079
Changes in non-cash working capital related to:		
Operating activities	$ (52,070)	$ 39,448
Investing activities	(62,485)	32,435
Foreign currency translation on non-cash working capital	1,697	(3,804)
	$ (112,858)	$ 68,079

Income Statement Presentation

Baytex's consolidated statements of income or loss and comprehensive income or loss are prepared primarily according to the nature of expense, with the exception of employee compensation costs which are included in both operating expense and general and administrative expense line items.

The following table details the amount of total employee compensation costs included in the operating expense and general and administrative expense.

	Years Ended December 31	
	2019	2018
Operating	$ 12,918	$ 12,140
General and administrative	33,728	34,963
Total employee compensation costs	$ 46,646	$ 47,103

22. COMMITMENTS AND CONTINGENCIES

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 of funding of these obligations, are noted in the table below.

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
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	$ 155,351	$ 21,870	$ 51,854	$ 45,947	$ 35,680

Baytex also has ongoing obligations related to the abandonment and reclamation of well sites and facilities which have reached the end of their economic lives. The present value of the future estimated abandonment and reclamation costs are included in the asset retirement obligations presented in the statements of financial position. Programs to abandon and reclaim wellsites and facilities are undertaken regularly in accordance with applicable legislative requirements.

23. RELATED PARTIES

Balances and transactions between the Company and its subsidiaries, which are related parties of the Company, have been eliminated on consolidation and are not disclosed separately in this note.

Transactions with key management personnel and directors are noted in the table below.

	Years Ended December 31	
	2019	2018
Short-term employee benefits	**$ 6,202**	$ 8,703
Share-based compensation	**9,188**	10,985
Termination payments	**2,208**	3,025
Total compensation for key management personnel	**$ 17,598**	$ 22,713

24. CAPITAL MANAGEMENT

The Company's capital management objective is to maintain financial flexibility and sufficient sources of liquidity to execute its capital programs, while meeting short and long-term commitments. Baytex strives to actively manage its capital structure in response to changes in economic conditions. At December 31, 2019, the Company's capital structure was comprised of shareholders' capital, long-term debt, working capital and the bank loan.

Baytex monitors its estimated adjusted funds flow and the level of undrawn credit facilities. The Company's 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 its capital structure and liquidity, Baytex may from time to time issue equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

At December 31, 2019, Baytex was in compliance with all of the covenants contained in the credit facilities and had unused capacity of $523.8 million (December 31, 2018 - $547.7 million).

Baytex considers adjusted funds flow a key measure that provides a more complete understanding of operating performance and the Company's ability to generate funds for capital investments, debt repayment, settlement of abandonment obligations and potential future dividends. Baytex eliminates changes in non-cash working capital, transaction costs, and settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on the Company's capital programs and the maturity of its operating areas. The settlement of abandonment obligations are managed through the 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 Baytex is able to provide a more meaningful measure of cash flow on a continuing basis. Transaction costs associated with business combinations (note 4) are excluded from adjusted funds flow as the costs are considered non-recurring and not reflective of the Company's 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 IFRS, such as cash flow from operating activities and net income or loss.

Adjusted funds flow does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures for other entities. It is reconciled to the nearest measure determined in accordance with IFRS, cash flow from operating activities, as set forth below.

	Years Ended December 31	
	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

The Company believes that net debt assists in providing a more complete understanding of its financial position and provides a key measure to assess liquidity. Net debt is calculated based on the principal amounts of the bank loan and long-term notes outstanding, net of 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. The principal amounts of the bank loan and long-term notes outstanding are used in the calculation of net debt as these amounts represent the Company's 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.

Net debt does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measure for other entities. The computation of net debt is set forth below.

	December 31, 2019	December 31, 2018
Bank loan - principal	**$ 506,471**	$ 522,294
Long-term notes - principal	**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

PETROLEUM AND NATURAL GAS RESERVES AS AT DECEMBER 31, 2019

Baytex's year-end 2019 proved and probable reserves were evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel"), an independent qualified reserves evaluator. All of our oil and gas properties were evaluated in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") using the average commodity price forecasts and inflation rates of McDaniel, GLJ Petroleum Consultants ("GLJ") and Sproule Associates Limited ("Sproule") as of January 1, 2020. Reserves associated with our thermal heavy oil projects at Peace River, Gemini (Cold Lake) and Kerrobert have been classified as bitumen.

Complete reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2019, which will be filed on or before March 30, 2020.

The following table sets forth our gross and net reserves volumes at December 31, 2019 by product type and reserves category. Please note that the data in the table may not add due to rounding.

Reserves Summary

Reserves Summary	Light and Medium Oil (mbbls)	Tight Oil (mbbls)	Heavy Oil (mbbls)	Bitumen (mbbls)	Total Oil (mbbls)	Natural Gas Liquids [3] (mbbls)	Conventional Natural Gas [4] (mmcf)	Shale Gas (mmcf)	Total [5] (mboe)
Gross [1]									
Proved producing	27,297	23,273	28,050	2,711	81,331	34,218	56,743	99,628	141,611
Proved developed non-producing	—	39	570	7,196	7,805	388	2,492	1,018	8,778
Proved undeveloped	33,322	32,250	22,691	1,892	90,155	43,333	45,272	133,516	163,286
Total proved	60,619	55,562	51,311	11,799	179,291	77,939	104,506	234,162	313,674
Total probable	31,218	24,139	37,805	53,743	146,905	35,654	99,816	99,739	215,818
Proved plus probable	91,837	79,701	89,116	65,542	326,196	113,592	204,323	333,901	529,492
Net [2]									
Proved producing	25,447	17,245	24,818	2,504	70,015	25,470	53,003	74,009	116,654
Proved developed non-producing	—	29	483	6,766	7,278	287	2,022	757	8,029
Proved undeveloped	31,052	24,029	20,371	1,873	77,325	32,206	40,444	99,106	132,789
Total proved	56,499	41,303	45,672	11,144	154,618	57,963	95,469	173,872	257,471
Total probable	28,703	18,214	32,813	43,031	122,761	26,797	90,061	74,952	177,060
Proved plus probable	85,201	59,517	78,486	54,175	277,379	84,760	185,530	248,823	434,531

Notes:

(1) "Gross" reserves means the total working interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.

(2) "Net" reserves means Baytex's gross reserves less all royalties payable to others plus royalty interest reserves.

(3) Natural Gas Liquids includes condensate.

(4) Conventional Natural Gas includes associated, non-associated and solution gas.

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

Reserves Reconciliation

The following table reconciles the year-over-year changes in our gross reserves volumes by product type and reserves category. Please note that the data in the table may not add due to rounding.

Proved Reserves – Gross Volumes [(1)] (Forecast Prices)

	Light and Medium Oil (mbbls)	Tight Oil (mbbls)	Heavy Oil (mbbls)	Bitumen (mbbls)	Total Oil (mbbls)	Natural Gas Liquids [(4)] (mbbls)	Conventional Natural Gas [(5)] (mmcf)	Shale Gas (mmcf)	Total [(6)] (mboe)
December 31, 2018	71,545	52,819	49,613	12,805	186,783	74,614	168,104	151,156	314,607
Product Type Transfer [(2)]	—	—	—	—	—	—	(57,548)	57,548	—
Extensions	7,328	7,510	4,845	—	19,683	8,260	6,225	26,200	33,347
Technical Revisions [(3)]	(9,133)	1,865	9,012	(341)	1,403	2,109	8,463	21,868	8,567
Acquisitions	1,264	—	18	—	1,282	2	227	—	1,322
Dispositions	(2,347)	—	—	—	(2,347)	—	(90)	—	(2,362)
Economic Factors	(217)	(1,232)	(3,201)	118	(4,531)	(625)	(3,590)	(2,393)	(6,153)
Production	(7,822)	(5,401)	(8,977)	(784)	(22,983)	(6,421)	(17,285)	(20,216)	(35,653)
December 31, 2019	60,619	55,562	51,311	11,799	179,291	77,939	104,506	234,162	313,674

Probable Reserves – Gross Volumes [(1)] (Forecast Prices)

	Light and Medium Oil (mbbls)	Tight Oil (mbbls)	Heavy Oil (mbbls)	Bitumen (mbbls)	Total Oil (mbbls)	Natural Gas Liquids [(4)] (mbbls)	Conventional Natural Gas [(5)] (mmcf)	Shale Gas (mmcf)	Total [(6)] (mboe)
December 31, 2018	20,941	21,879	42,687	55,545	141,052	38,473	122,685	71,550	211,898
Product Type Transfer [(2)]	—	—	—	—	—	—	(24,653)	24,653	—
Extensions	8,761	2,877	(363)	—	11,275	63	(473)	2,504	11,676
Technical Revisions [(3)]	1,696	768	(4,317)	(1,887)	(3,740)	(1,590)	2,822	5,923	(3,873)
Acquisitions	416	—	5	—	420	1	82	—	435
Dispositions	(579)	—	—	—	(579)	—	(27)	—	(583)
Economic Factors	(17)	(1,385)	(207)	85	(1,524)	(1,293)	(619)	(4,890)	(3,735)
Production	—	—	—	—	—	—	—	—	—
December 31, 2019	31,218	24,139	37,805	53,743	146,905	35,654	99,816	99,739	215,818

Proved Plus Probable Reserves – Gross Volumes [(1)] (Forecast Prices)

	Light and Medium Oil (mbbls)	Tight Oil (mbbls)	Heavy Oil (mbbls)	Bitumen (mbbls)	Total Oil (mbbls)	Natural Gas Liquids [(4)] (mbbls)	Conventional Natural Gas [(5)] (mmcf)	Shale Gas (mmcf)	Total [(6)] (mboe)
December 31, 2018	92,487	74,698	92,301	68,350	327,836	113,087	290,789	222,706	526,505
Product Type Transfer [(2)]	—	—	—	—	—	—	(82,200)	82,200	—
Extensions	16,089	10,387	4,482	—	30,958	8,323	5,752	28,703	45,023
Technical Revisions [(3)]	(7,437)	2,634	4,695	(2,228)	(2,337)	518	11,285	27,790	4,695
Acquisitions	1,680	—	23	—	1,702	3	309	—	1,757
Dispositions	(2,926)	—	—	—	(2,926)	—	(118)	—	(2,945)
Economic Factors	(234)	(2,616)	(3,408)	204	(6,054)	(1,919)	(4,209)	(7,283)	(9,888)
Production	(7,822)	(5,401)	(8,977)	(784)	(22,983)	(6,421)	(17,285)	(20,216)	(35,653)
December 31, 2019	91,837	79,701	89,116	65,542	326,196	113,592	204,323	333,901	529,492

Notes:

(1) "Gross" reserves means the total working interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.

(2) Product type transfer reflects the reclassification of solution gas in the Eagle Ford from conventional natural gas to shale gas.

(3) Positive technical revisions for heavy oil are largely the results of positive production performance versus previous forecasts in both our Lloydminster and Peace River areas. Positive conventional natural gas revisions are predominately related to the solution gas associated with our heavy oil assets. Positive technical revisions in the tight oil and shale gas are a result of enhanced type well profiles in our Eagle Ford acreage. Negative technical revisions in the light and medium oil are associated with our Viking area and are predominately a result of a reduction in later life reserves associated with the production profile.

(4) Natural gas liquids include condensate.

(5) Conventional natural gas includes associated, non-associated and solution gas.

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

Future Development Costs

The following table sets forth future development costs deducted in the estimation of the future net revenue attributable to the reserves categories noted below.

Future Development Costs ($ millions)	Proved Reserves	Proved Plus Probable Reserves
2020	530	536
2021	522	562
2022	563	625
2023	444	611
2024	496	848
Remainder	2	1,132
Total FDC undiscounted	2,558	4,315

F&D and FD&A Costs – including future development costs

Based on the evaluation of our petroleum and natural gas reserves prepared by McDaniel, the efficiency of our capital program is summarized in the following table.

millions except for per boe amounts	2019	2018	2017	3 Year
Proved plus Probable Reserves				
Finding & Development Costs				
Exploration and development expenditures	$552.3	$495.7	$326.3	$1,374.3
Net change in Future Development Costs	$96.7	$132.3	($76.4)	$152.7
Gross Reserves additions (mmboe)	39.8	31.2	34.4	105.5
F&D Costs ($/boe)	$16.30	$20.11	$7.26	$14.48
Finding, Development & Acquisition (“FD&A”) Costs				
Exploration and development expenditures and net acquisitions	$554.5	$2,099.6	$386.1	$3,040.2
Net change in Future Development Costs	$79.9	$1,064.5	$84.2	$1,228.6
Gross Reserves additions (mmboe)	38.6	123.9	51.6	214.1
FD&A Costs ($/boe)	$16.42	$25.55	$9.11	$19.94
Proved Reserves				
Finding & Development Costs				
Exploration and development expenditures	$552.3	$495.7	$326.3	$1,374.3
Net change in Future Development Costs	($90.4)	$117.4	($132.6)	($105.6)
Gross Reserves additions (mmboe)	35.8	17.5	21.7	74.9
F&D Costs ($/boe)	$12.92	$35.05	$8.93	$16.93
Finding, Development & Acquisition Costs				
Exploration and development expenditures and net acquisitions	$554.5	$2,099.6	$386.1	$3,040.2
Net change in Future Development Costs	($107.2)	$987.4	($97.1)	$783.1
Gross Reserves additions (mmboe)	34.7	88.4	28.5	151.7
FD&A Costs ($/boe)	$12.88	$34.91	$10.13	$25.21
Proved Developed Producing Reserves				
Finding & Development Costs				
Exploration and development expenditures	$552.3	$495.7	$326.3	$1,374.3
Gross Reserves additions (mmboe)	42.5	31.3	23.8	97.4
F&D Costs ($/boe)	$13.04	$15.82	$13.73	$14.10
Finding, Development & Acquisition Costs				
Exploration and development expenditures and net acquisitions	$554.5	$2,099.6	$386.1	$3,040.2
Gross Reserves additions (mmboe)	42.5	63.7	27.5	133.7
FD&A Costs ($/boe)	$13.04	$32.95	$14.06	$22.73

Reserves Life Index

The following table sets forth our reserves life index, which is calculated by dividing our proved and proved plus probable reserves at year-end 2019 by annualized Q4/2019 production.

	Q4/2019 Production	Reserves Life Index (years) Proved	Proved Plus Probable
Crude Oil and NGL (bbl/d)	79,655	8.8	15.1
Natural Gas (mcf/d)	100,234	9.3	14.7
Oil Equivalent (boe/d)	96,360	8.9	15.1

Forecast Prices and Costs

The following table summarizes the forecast prices used in preparing the estimated reserves volumes and the net present values of future net revenues at December 31, 2019. The estimated future net revenue to be derived from the production of the reserves is based on the following average of the price forecasts of McDaniel, GLJ and Sproule as of January 1, 2020.

Year	WTI Crude Oil US$/bbl	Edmonton Light Crude Oil $/bbl	Western Canadian Select $/bbl	Henry Hub US$/MMbtu	AECO Spot $/MMbtu	Inflation Rate %/Yr	Exchange Rate $US/$Cdn
2019 act.	56.95	68.65	58.10	2.55	1.60	2.0	0.750
2020	61.00	72.64	57.57	2.62	2.04	0.0	0.760
2021	63.75	76.06	62.35	2.87	2.32	1.7	0.770
2022	66.18	78.35	64.33	3.06	2.62	2.0	0.785
2023	67.91	80.71	66.23	3.17	2.71	2.0	0.785
2024	69.48	82.64	67.97	3.24	2.81	2.0	0.785
2025	71.07	84.60	69.72	3.32	2.89	2.0	0.785
2026	72.68	86.57	71.49	3.39	2.96	2.0	0.785
2027	74.24	88.49	73.20	3.45	3.03	2.0	0.785
2028	75.73	90.31	74.80	3.53	3.09	2.0	0.785
2029	77.24	92.17	76.43	3.60	3.16	2.0	0.785
Thereafter		Escalation rate of 2.0%				2.0	0.785

Net Present Value of Reserves (1) (Forecast Prices and Costs)

The following table summarizes the McDaniel estimate of the net present value before income taxes of the future net revenue attributable to our reserves.

Reserves at December 31, 2019 ($ millions, discounted at)	0%	5%	10%	15%
Proved developed producing	2,640	2,501	2,211	1,965
Proved developed non-producing	179	118	81	57
Proved undeveloped	3,256	2,096	1,419	991
Total proved	6,075	4,714	3,710	3,013
Probable	5,627	3,029	1,890	1,298
Total Proved Plus Probable (before tax)	11,702	7,743	5,600	4,310

Note:

(1) Includes abandonment, decommissioning and reclamation costs for all producing and nonproducing wells and facilities.

Net Asset Value (Forecast Prices and Costs)

Our estimated net asset value is based on the estimated net present value of all future net revenue from our reserves, before income taxes, as estimated by McDaniel at year-end, plus the estimated value of our undeveloped land holdings, less net debt. This calculation can vary significantly depending on the oil and natural gas price assumptions. In addition, this calculation does not consider "going concern" value and assumes only the reserves identified in the reserves reports with no further acquisitions or incremental development.

The following table sets forth our net asset value as at December 31, 2019.

($ millions, except per share amounts, discounted at)	**5%**	**10%**	**15%**
Net present value of proved plus probable reserves (1)	7,743	5,600	4,310
Undeveloped land holdings (2)	162	162	162
Net Debt	(1,871)	(1,871)	(1,871)
Net Asset Value	6,034	3,891	2,601
Net Asset Value per Share (3)	10.81	6.97	4.66

Notes:

(1) Includes abandonment, decommissioning and reclamation costs for all producing and nonproducing wells and facilities.
(2) The value of undeveloped land holdings generally represents the estimated replacement cost of our undeveloped land.
(3) Based on 558.3 million common shares outstanding as at December 31, 2019.

Advisory Regarding Oil and Gas Information

The reserves information contained in this report have been prepared in accordance with NI 51-101. Complete NI 51-101 reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2019, which will be filed on or before March 30, 2020. Listed below are cautionary statements that are specifically required by NI 51-101:

- The term barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one boe (6 mcf/bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

- With respect to finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

- This press release contains estimates of the net present value of our future net revenue from our reserves. Such amounts do not represent the fair market value of our reserves.

This report contains metrics commonly used in the oil and natural gas industry, such as "capital efficiencies", "finding and development costs", "finding, development and acquisition costs", "net asset value", "recycle ratio," "operating netback," and "reserves life index." These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included in this press release to provide readers with additional measures to evaluate Baytex's performance, however, such measures are not reliable indicators of Baytex's future performance and future performance may not compare to Baytex's performance in previous periods and therefore such metrics should not be unduly relied upon.

In this report, “oil and NGL” refers to heavy oil, bitumen, light and medium oil, tight oil, condensate and natural gas liquids (“NGL”) product types as defined by NI 51-101. The following table shows Baytex’s disaggregated production volumes for the year ended December 31, 2019. The NI 51-101 product types are included as follows: “Heavy Oil” - heavy oil and bitumen, “Light and Medium Oil” - light and medium oil, tight oil and condensate, “NGL” - natural gas liquids and “Natural Gas” - shale gas and conventional natural gas.

	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada - Heavy					
Peace River	14,334	14	45	14,503	16,810
Lloydminster	12,407	—	—	964	12,568
Canada - Light					
Viking	—	20,527	125	11,361	22,546
Duvernay	—	928	491	1,613	1,688
Remaining properties	—	889	703	20,528	5,013
United States					
Eagle Ford	—	21,229	8,865	53,773	39,055
Total	26,741	43,587	10,229	102,742	97,680

Capital efficiency means the cost to drill, complete, equip and tie-in a well divided by the initial production rate of the well on a boe basis over its initial 365 days of production.

Finding and development costs are calculated on a per boe basis by dividing the aggregate of the change in future development costs from the prior year for the particular reserve category and the costs incurred on exploration and development activities in the year by the change in reserves from the prior year for the reserve category.

Finding, development and acquisition costs are calculated on a per boe basis by dividing the aggregate of the change in future development costs from the prior year for the particular reserve category and the costs incurred on development and exploration activities and property acquisitions (net of dispositions) in the year by the change in reserves from the year for the reserve category

Net asset value has been calculated based on the estimated net present value of all future net revenue from our reserves, before income taxes, as estimated by McDaniel effective December 31, 2019, plus the estimated value of our undeveloped land holdings, less net debt.

Recycle ratio means operating netback divided by finding and development costs for the particular reserves category.

Reserve life index means the reserves for the particular reserve category divided by annualized 2019 fourth quarter production.

This report discloses drilling inventory and potential drilling locations. Drilling inventory and drilling locations refers to Baytex’s total proved, probable and unbooked locations. Proved locations and probable locations account for drilling locations in our inventory that have associated proved and/or probable reserves. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves. Unbooked locations are farther away from existing wells and, therefore, there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty whether such wells will result in additional oil and gas reserves, resources or production. In the Eagle Ford, Baytex’s net drilling locations include 140 proved and 83 probable locations as at December 31, 2019 and 52 unbooked locations. In the Viking, Baytex’s net drilling locations include 1,080 proved and 319 probable locations as at December 31, 2019 and 636 unbooked locations. In Peace River, Baytex’s net drilling locations include 77 proved and 75 probable locations as at December 31, 2019 and 100 unbooked locations. In Lloydminster, Baytex’s net drilling locations include 178 proved and 63 probable locations as at December 31, 2019 and 361 unbooked locations. In the Duvernay, Baytex’s net drilling locations include 11 proved and 10 probable locations as at December 31, 2019 and 295 unbooked locations.

Notice to United States Readers

The petroleum and natural gas reserves contained in this report have generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. For example, the United States Securities and Exchange Commission (the "SEC") requires oil and gas issuers, in their filings with the SEC, to disclose only "proved reserves", but permits the optional disclosure of "probable reserves" (each as defined in SEC rules). Canadian securities laws require oil and gas issuers disclose their reserves in accordance with NI 51-101, which requires disclosure of not only "proved reserves" but also "probable reserves". Additionally, NI 51-101 defines "proved reserves" and "probable reserves" differently from the SEC rules. Accordingly, proved and probable reserves disclosed in this report may not be comparable to United States standards. Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves.

In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross volumes, which are volumes prior to deduction of royalty and similar payments. The SEC rules require reserves and production to be presented using net volumes, after deduction of applicable royalties and similar payments.

Moreover, Baytex has determined and disclosed estimated future net revenue from its reserves using forecast prices and costs, whereas the SEC rules require that reserves be estimated using a 12-month average price, calculated as the arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. As a consequence of the foregoing, Baytex's reserve estimates and production volumes in this report may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

ABBREVIATIONS

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

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

Corporate Information

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Director

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Director

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

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Chief Executive Officer

Rodney D. Gray
Executive Vice President
and Chief Financial Officer

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Vice President, Finance

Scott Lovett
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Corporate Development

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KPMG LLP

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ATB Financial
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Barclays Bank plc
Canadian Imperial Bank of Commerce
Caisse Centrale Desjardins
Export Development Canada
National Bank of Canada
Royal Bank of Canada
The Toronto-Dominion Bank
Wells Fargo Bank

RESERVES ENGINEERS

McDaniel & Associates Consultants Ltd.

TRANSFER AGENT

Computershare Trust
Company of Canada

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New York Stock Exchange
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Symbol
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Design: ARTHUR / HUNTER

Printing: Merrill Corporation

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