BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the years ended December 31, 2021 and 2020
Dated February 24, 2022

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, 2021 and 2020. This information is provided as of February 24, 2022. 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, 2021 ("Q4/2021" and "2021") have been compared with the results for the three months and year ended December 31, 2020 ("Q4/2020" and "2020"). 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, 2021 and 2020, together with the accompanying notes and the Annual Information Form ("AIF") for the year ended December 31, 2021. 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 in accordance with International Financial Reporting Standards ("IFRS") as prescribed by the International Accounting Standards Board. The terms "operating netback", "free cash flow", "average royalty rate", "heavy oil, net of blending and other expense" and "total sales, net of blending and other expense" are specified financial measures that do not have any standardized meaning as prescribed by IFRS and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. This MD&A also contains the terms "adjusted funds flow", "net debt" and "net debt to adjusted funds flow ratio" which are capital management measures. Refer to our advisory on forward-looking information and statements and a summary of our specified financial measures at the end of the MD&A.

BAYTEX ENERGY CORP.

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

2021 ANNUAL HIGHLIGHTS

Baytex delivered strong operating and financial results in 2021. Energy prices strengthened with increasing demand as economies recovered from the COVID-19 pandemic and supply remained limited by OPEC production curtailments along with restricted oil and gas investment globally. As a result, WTI averaged US$67.92/bbl for 2021 which was a US$28.52/bbl increase from 2020 when WTI averaged US$39.40/bbl. With higher commodity prices, we generated adjusted funds flow(1) of $745.6 million and free cash flow(2) of $421.3 million which contributed to a $437.9 million reduction in net debt(1). Strong well performance across all of our assets resulted in production of 80,156 boe/d which was slightly above the high end of our annual guidance range of 77,000 - 79,000 boe/d. Our disciplined approach to capital allocation and continued focus on reducing our cost structure has improved the results we have achieved as commodity prices have increased.

Exploration and development expenditures were $313.3 million in 2021 with $208.2 million invested in Canada and $105.1 million in the U.S. In Canada, we drilled 37 (33.5 net) heavy oil wells, including 8 (8.0 net) wells in our developing Clearwater play, and 125 (123.2 net) light oil wells which resulted in production of 49,424 boe/d for 2021 compared to 48,602 boe/d in 2020. In the U.S., production of 30,731 boe/d for 2021 reflects our successful development activity which restored production to be consistent with 31,179 boe/d in 2020 when spending was limited in response to low commodity prices. In 2021, we brought 93 (23.1 net) wells on production compared to 2020 where we brought 62 (14.1 net) wells on production.

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

Adjusted funds flow[1] of $745.6 million in 2021 increased $434.1 million from 2020 due to the increase in oil and natural gas prices relative to 2020 when adjusted funds flow was $311.5 million. Improved pricing was the main factor contributing to a $664.5 million increase in operating netback[2] in 2021 compared to 2020. Our strong operating and financial results generated net income of $1.6 billion for 2021 which included impairment reversals of $1.5 billion compared to a net loss of $2.6 billion for 2020 which included impairment write-downs of $2.4 billion.

We used our 2021 free cash flow[2] of $421.3 million to reduce our net debt[1] to $1.41 billion at December 31, 2021 which was $437.9 million lower compared to $1.85 billion at December 31, 2020. As part of our debt reduction we repurchased and cancelled US$200 million of the 5.625% Notes due in 2024 during 2021. At December 31, 2021, US$200.0 million of the 2024 Notes and US$500 million of the 2027 Notes remain outstanding.

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

GUIDANCE

The following table compares our 2021 annual guidance to our 2021 results. We delivered production that exceeded our annual guidance with exploration and development expenditures that approximated the high end of our guidance range. Expenses and lease expenditures were within or slightly below our annual guidance as a result of our continued efforts to control costs.

	Original Annual Guidance[1]	Revised Annual Guidance[2]	2021 Results
Exploration and development expenditures	$225 - $275 million	$285 - $315 million	$313 million
Production (boe/d)	73,000 - 77,000	77,000 - 79,000	80,156
Expenses:			
Average royalty rate[3]	18.0% - 18.5%	18.0% - 18.5%	19.0 %
Operating[4]	$11.50 - $12.25/boe	$11.25 - $12.00/boe	$11.72/boe
Transportation[4]	$1.00 - $1.10/boe	$1.15 - $1.25/boe	$1.10/boe
General and administrative[4]	$42 million ($1.53/boe)	$42 million ($1.48/boe)	$41 million ($1.39/boe)
Cash Interest[4]	$105 million ($3.84/boe)	$98 million ($3.46/boe)	$92 million ($3.15/boe)
Leasing expenditures	$4 million	$4 million	$4 million
Asset retirement obligations	$6 million	$6 million	$7 million

(1) As announced on December 2, 2020.
(2) As announced on April 29, 2021. This guidance reference date included the introduction of a five-year outlook. 2021 guidance was subsequently tightened on November 4, 2021, reflecting year-to-date results, to $300 to $315 million for exploration and development expenditures, 79,500 to 80,000 boe/d for production, 18.5% to 19.0% for royalty rates, $11.25/boe to $11.75/boe for operating expenses, $1.10/boe to $1.15/boe for transportation expenses and $92 million ($3.16/boe) for interest expense.
(3) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.
(4) Refer to Operating Expense, Transportation Expense, General and Administrative Expense and Financing and Interest Expense sections of this MD&A for description of the composition of these measures.

On December 1, 2021 our Board of Directors approved our 2022 budget which included exploration and development expenditures of $400 - $450 million that is designed to generate production of 80,000 - 83,000 boe/d. The program is expected to be equally weighted between the first and second half of 2022. Additional activity and Clearwater development in 2022 will result in exploration and development expenditures of $400 - $450 million in 2022 compared to $313 million in 2021. The increase in asset retirement obligations settled in 2022 relative to 2021 reflects our commitment to reduce our inactive wellbore count. We expect lower interest expense in 2022 relative to 2021 due to lower net debt as we continue to use free cash flow for debt repayment.

The following table compares our 2022 annual guidance as released on December 1, 2021 to our 2021 results.

	2022 Guidance	2021 Results
Exploration and development expenditures	$400 - $450 million	$313 million
Production (boe/d)	80,000 - 83,000	80,156
Expenses:		
Average royalty rate(1)	18.5% - 19.0%	19.0 %
Operating(2)	$12.25 - $13.00/boe	$11.72/boe
Transportation(2)	$1.20 - $1.30/boe	$1.10/boe
General and administrative(2)	$43 million ($1.45/boe)	$41 million ($1.39/boe)
Cash Interest(2)	$80 million ($2.70/boe)	$92 million ($3.15/boe)
Leasing expenditures	$3 million	$4 million
Asset retirement obligations settled (3)	$20 million	$7 million

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

(2) Refer to Operating Expense, Transportation Expense General and Administrative Expense and Financing and Interest Expense sections of this MD&A for description of the composition of these measures.

(3) Government grants reduced asset retirement obligations by $3 million in 2021. In 2022 we expect government grants to reduce asset retirement obligations by $15 million.

RESULTS OF OPERATIONS

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.

Production

	Years Ended December 31					
	2021			2020		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**16,943**	**18,846**	**35,789**	19,103	17,953	37,056
Heavy oil	**22,188**	**—**	**22,188**	21,142	—	21,142
Natural Gas Liquids ("NGL")	**1,671**	**5,573**	**7,244**	1,224	6,116	7,340
Total liquids (bbl/d)	**40,802**	**24,419**	**65,221**	41,469	24,069	65,538
Natural gas (mcf/d)	**51,733**	**37,874**	**89,606**	42,799	42,665	85,464
Total production (boe/d)	**49,424**	**30,731**	**80,156**	48,602	31,179	79,781
Production Mix						
Segment as a percent of total	**62 %**	**38 %**	**100 %**	61 %	39 %	100 %
Light oil and condensate	**34 %**	**61 %**	**45 %**	39 %	58 %	46 %
Heavy oil	**45 %**	**— %**	**28 %**	44 %	— %	27 %
NGL	**3 %**	**18 %**	**9 %**	3 %	20 %	9 %
Natural gas	**18 %**	**21 %**	**18 %**	14 %	22 %	18 %

Production of 80,156 boe/d in 2021 was consistent with 79,781 boe/d in 2020. Production declined from Q1/2020 to Q2/2020 due to the sharp decline in crude oil prices in March 2020 when we shut-in production in Canada and moderated the pace of activity in the U.S. Commodity prices began to recover in Q3/2020 and have strengthened throughout 2021 which supported increased development activity and resulted in production of 80,789 boe/d for Q4/2021 relative to 70,475 boe/d in Q4/2020.

In Canada, total production of 49,424 boe/d in 2021 was consistent with 48,602 boe/d in 2020 as our successful 2021 development program restored production after development activity was limited and production declined throughout 2020. In the U.S., production was 30,731 boe/d in 2021 compared to 31,179 boe/d for 2020. Production levels were consistent year over year as successful development program in 2021 restored production levels that declined throughout 2020 when development spending was limited.

Total production of 80,156 boe/d for 2021 was slightly above our revised guidance of 77,000 - 79,000 boe/d which reflects strong well performance from our successful development programs in the U.S. and Canada. We expect production in 2022 to average 80,000 - 83,000 boe/d in 2022 which is a modest increase from 2021.

Commodity Prices

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

Crude Oil

Global benchmark prices for crude oil were strong throughout 2021. Oil supply was impacted by OPEC production curtailments and limited production growth from large independent producers while the outlook for oil demand improved as global economic activity increased and economies recovered from the pandemic. These factors resulted in the WTI benchmark price averaging US$67.92/bbl for 2021 which is US$28.52/bbl higher relative to US$39.40/bbl for 2020.

We compare the price received for our U.S. crude oil production to the Magellan East Houston ("MEH") stream at Houston, Texas which is a representative benchmark for light oil pricing at the U.S. Gulf coast. The MEH benchmark averaged US$69.26/bbl during 2021, representing a premium of US$1.34/bbl relative to WTI, compared to US$40.15/bbl or a premium of US$0.75/bbl for 2020.

Prices for Canadian oil trade at a discount to WTI due to a lack of egress to diversified markets from Western Canada. Differentials for Canadian oil prices relative to WTI fluctuate from period to period based on production and inventory levels in Western Canada.

We compare the price received for our light oil production in Canada to the Edmonton par benchmark oil price. The Edmonton par price averaged $80.23/bbl for 2021 compared to $45.34/bbl for 2020. Edmonton par traded at a US$3.92/bbl discount to WTI in 2021 which is tighter than a discount of US$5.60/bbl for 2020 as a result of incremental egress with the Line 3 expansion and higher demand for Canadian light oil.

We compare the price received for our heavy oil production in Canada to the WCS heavy oil benchmark. The WCS heavy oil price for 2021 averaged $68.79/bbl compared to $35.95/bbl for 2020. The increase in the WCS heavy oil benchmark is a result of the higher WTI price as the differential of US$13.05/bbl in 2021 was relatively consistent with the differential of US$12.60/bbl during 2020.

Natural Gas

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$3.84/mmbtu for 2021 which is higher than US$2.08/mmbtu for 2020 as strong demand and lower U.S. production resulted in reduced inventory levels for 2021 relative to 2020.

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 limited market access for Canadian natural gas production. The AECO benchmark averaged $3.56/mcf during 2021 compared to $2.24/mcf during 2020. The AECO benchmark was higher in 2021 relative to 2020 due to lower production and increased demand for natural gas which resulted in reduced inventory levels in Canada.

The following tables compare select benchmark prices and our average realized selling prices for the years ended December 31, 2021 and 2020.

	Years Ended December 31		
	2021	2020	Change
Benchmark Averages			
WTI oil (US$/bbl)[1]	**67.92**	39.40	28.52
MEH oil (US$/bbl)[2]	**69.26**	40.15	29.11
MEH oil differential to WTI (US$/bbl)	**1.34**	0.75	0.59
Edmonton par oil ($/bbl)[3]	**80.23**	45.34	34.89
Edmonton par oil differential to WTI (US$/bbl)	**(3.92)**	(5.60)	1.68
WCS heavy oil ($/bbl)[4]	**68.79**	35.95	32.84
WCS heavy oil differential to WTI (US$/bbl)	**(13.05)**	(12.60)	(0.45)
AECO natural gas price ($/mcf)[5]	**3.56**	2.24	1.32
NYMEX natural gas price (US$/mmbtu)[6]	**3.84**	2.08	1.76
CAD/USD average exchange rate	**1.2536**	1.3413	(0.0877)

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

	2021			2020		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl)[1]	**$ 77.65**	**$ 85.14**	**$ 81.59**	$ 42.35	$ 49.84	$ 45.98
Heavy oil, net of blending and other expense ($/bbl)[2]	**58.65**	**—**	**58.65**	24.28	—	24.28
NGL ($/bbl)[1]	**30.99**	**37.17**	**35.74**	13.47	15.57	15.22
Natural gas ($/mcf)[1]	**3.62**	**5.70**	**4.50**	2.13	2.65	2.39
Total sales, net of blending and other expense ($/boe)[2]	**$ 57.79**	**$ 65.98**	**$ 60.93**	$ 29.42	$ 35.38	$ 31.75

Years Ended December 31

Average Realized Sales Prices

Our total sales, net of blending and other expense per boe was $60.93/boe for 2021 compared to $31.75/boe for 2020. In Canada, our realized sales price of $57.79/boe for 2021 was $28.37/boe higher than $29.42/boe for 2020. Our realized sales price in the U.S. was $65.98/boe in 2021 which is $30.60/boe higher than $35.38/boe in 2020. The increase in our realized price in Canada and the U.S. for 2021 was a result of higher North American benchmark prices relative to 2020.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Our realized light oil and condensate price in 2021 was $77.65/bbl compared to $42.35/bbl in 2020. Our realized light oil and condensate price for 2021 increased with the improvement in the benchmark price and represents a discount of $2.58/bbl to the Edmonton par benchmark which is consistent with a $2.99/bbl discount in 2020.

We compare the price received for our U.S. light oil and condensate production to the MEH benchmark. Our realized light oil and condensate price averaged $85.14/bbl for 2021 compared to $49.84/bbl for 2020. Expressed in U.S. dollars, our realized light oil and condensate price of US$67.92/bbl for 2021 reflects a US$1.34/bbl discount to the MEH benchmark for 2021 compared to a realized price of US$37.16/bbl and discount of US$2.99/bbl in 2020. Improved pricing on our contracts in place for 2021 have resulted in improved price realizations relative to 2020.

Our realized heavy oil price, net of blending and other expense[1] averaged $58.65/bbl in 2021 compared to $24.28/bbl in 2020. Our realized heavy oil price, net of blending and other expense for 2021 increased $34.37/bbl which is slightly higher than a $32.84/bbl increase in the WCS benchmark due to improved pricing on our rail contracts in place during 2021.

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 $35.74/bbl in 2021 or 42% of WTI (expressed in Canadian dollars) compared to $15.22/bbl or 29% of WTI (expressed in Canadian dollars) in 2020. Our realized NGL price was higher as a percentage of WTI in 2021 relative to 2020 due to strong global demand, incremental LNG export capacity and lower supply of NGLs in 2021.

We compare our realized natural gas price in Canada to the AECO benchmark price. Our realized natural gas price for 2021 was $3.62/mcf compared to $2.13/mcf in 2020. These realized prices were relatively consistent with the AECO benchmark price in both periods. In the U.S., our realized natural gas price was US$4.55/mcf for 2021 compared to US$1.98/mcf in 2020. A portion of our natural gas production is based on daily indexes which resulted in a US$0.71/mcf premium for our realized natural gas price when compared to the NYMEX benchmark for 2021 due to fluctuations in the daily index caused by severe weather events which disrupted supply and caused increased demand in the U.S. Gulf coast during 2021.

(1) Calculated as light oil and condensate, NGL or natural gas sales divided by barrels of oil equivalent production volume for the applicable period.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

Petroleum and Natural Gas Sales

	Years Ended December 31					
	2021			2020		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 480,199**	**$ 585,635**	**$ 1,065,834**	$ 296,125	$ 327,460	$ 623,585
Heavy oil	**560,696**	**—**	**560,696**	236,235	—	236,235
NGL	**18,904**	**75,611**	**94,515**	6,037	34,845	40,882
Total liquids sales	**1,059,799**	**661,246**	**1,721,045**	538,397	362,305	900,702
Natural gas sales	**68,338**	**78,812**	**147,150**	33,344	41,431	74,775
Total petroleum and natural gas sales	**1,128,137**	**740,058**	**1,868,195**	571,741	403,736	975,477
Blending and other expense	**(85,689)**	**—**	**(85,689)**	(48,381)	—	(48,381)
Total sales, net of blending and other expense(1)	**$ 1,042,448**	**$ 740,058**	**$ 1,782,506**	$ 523,360	$ 403,736	$ 927,096

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

Total sales, net of blending and other expense, of $1.78 billion for 2021 increased $0.86 billion or 92% from $0.93 billion for 2020. The increase in total sales, net of blending and other expense, in 2021 is a result of higher realized pricing due to the increase in benchmark pricing relative to 2020.

In Canada, total sales, net of blending and other expense, was $1.04 billion for 2021 which is an increase of $0.52 billion or 100% from $0.52 billion reported for 2020. In the U.S., petroleum and natural gas sales were $740.1 million for 2021 which is an increase of $336.3 million or 83% from $403.7 million reported for 2020. Total sales, net of blending and other expense, increased in Canada and the U.S. in 2021 due to higher oil and natural gas prices relative to 2020.

Royalties

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues or on operating netbacks less capital investment for specific heavy oil projects and are generally expressed as a percentage of total sales, net of blending and other expense. The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction. The following table summarizes our royalties and royalty rates for the years ended December 31, 2021 and 2020.

	Years Ended December 31					
	2021			2020		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 121,306**	**$ 217,850**	**$ 339,156**	$ 46,064	$ 117,671	$ 163,735
Average royalty rate(1)(2)	**11.6 %**	**29.4 %**	**19.0 %**	8.8 %	29.1 %	17.7 %
Royalties per boe(3)	**$ 6.72**	**$ 19.42**	**$ 11.59**	$ 2.59	$ 10.31	$ 5.61

(1) Average royalty rate is calculated as royalties divided by total sales, net of blending and other expense.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.
(3) Royalties per boe is calculated as royalties divided by barrels of oil equivalent production volume for the applicable period.

Royalties for 2021 were $339.2 million or 19.0% of total sales, net of blending and other expense, compared to $163.7 million or 17.7% in 2020. Total royalty expense was higher in 2021 due to higher total sales, net of blending and other expense, relative to 2020. Our average royalty rate of 19.0% for 2021 is higher than 17.7% for 2020 due to a higher royalty rate on our Canadian properties as a result of higher commodity prices. Our average royalty rate of 19.0% for 2021 is consistent with our annual guidance range of 18.0% - 18.5% for 2021.

In Canada, the average royalty rate was 11.6% in 2021 which was higher than 8.8% for 2020 as certain production in Canada is subject to higher royalty rates with higher benchmark commodity prices. In the U.S., the average royalty rate was 29.4% for 2021 which is consistent with 29.1% for 2020 as the royalty rate on our U.S. production does not vary with price but can vary across our acreage.

We expect our average royalty rate to be 18.5% - 19.0% in 2022 which is consistent with 2021.

Operating Expense

	Years Ended December 31					
	2021			2020		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 257,658**	**$ 85,344**	**$ 343,002**	$ 247,050	$ 84,295	$ 331,345
Operating expense per boe(1)	**$ 14.28**	**$ 7.61**	**$ 11.72**	$ 13.89	$ 7.39	$ 11.35

(1) Operating expense per boe is calculated as operating expense divided by barrels of oil equivalent production volume for the applicable period.

Total operating expense was $343.0 million ($11.72/boe) in 2021 compared to $331.3 million ($11.35/boe) in 2020. The increase in total operating expense is primarily attributed to a slight increase in per unit operating expenses. Operating expense of $11.72/boe for 2021 is consistent with our annual guidance range of $11.25 - $12.00/boe.

In Canada, operating expense was $257.7 million ($14.28/boe) for 2021 compared to $247.1 million ($13.89/boe) for 2020. The increase in total operating expense was a result of slightly higher production and a slight increase in per unit operating expense in 2021 relative to 2020. The increase in per unit operating expense to $14.28/boe for 2021 from $13.89/boe reported for 2020 was a result of reactivating higher cost production that was shut-in for a portion of 2020 in addition to an increase in fuel and electricity costs in 2021.

U.S. operating expense was $85.3 million ($7.61/boe) for 2021 compared to $84.3 million ($7.39/boe) for 2020. Expressed in U.S. dollars, per unit operating expense was US$6.07/boe for 2021 and was relatively consistent with US$5.51/boe for 2020 after normalizing for a $3.7 million credit recorded during 2020 for the reimbursement of prior period charges.

We expect annual operating expense of $12.25 - $13.00/boe for 2022 which reflects higher production in our Canadian operations relative to 2021.

Transportation Expense

Transportation expense includes the costs to move production from the field to the sales point. The largest component of transportation expense relates to the trucking of oil in Canada to pipeline and rail terminals which can vary from period to period depending on hauling distances as we seek to optimize sales prices and trucking rates.

The following table compares our transportation expense for the years ended December 31, 2021 and 2020.

	Years Ended December 31					
	2021			2020		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 32,261**	**$ —**	**$ 32,261**	$ 28,437	$ —	$ 28,437
Transportation expense per boe(1)	**$ 1.79**	**$ —**	**$ 1.10**	$ 1.60	$ —	$ 0.97

(1) Transportation expense per boe is calculated as transportation expense divided by barrels of oil equivalent production volume for the applicable period.

Transportation expense was $32.3 million ($1.10/boe) for 2021 compared to $28.4 million ($0.97/boe) for 2020. Total transportation expense increased in 2021 relative to 2020 as more volumes were trucked and we experienced higher per unit costs in 2021. Per unit transportation expense in Canada of $1.79/boe in 2021 is higher than $1.60/boe in 2020 as a result of increased trucking distances and higher fuel costs in 2021 relative to 2020. Transportation expense of $1.10/boe in 2021 is at the low end of our annual guidance range of $1.15 - $1.25/boe for 2021. We expect annual transportation expense of $1.20 - $1.30/boe per boe for 2022 which is higher than 2021 as we expect trucking rates to increase with higher fuel costs in 2022.

Blending and Other Expense

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

Blending and other expense was $85.7 million for 2021 compared to $48.4 million for 2020. The increase in blending and other expense in 2021 compared to 2020 is primarily the result of an increase in the price of condensate purchased as diluent in 2021 relative to 2020.

Financial Derivatives

As part of our normal operations, we are exposed to movements in commodity prices, foreign exchange rates, interest rates and changes in our share price. In an effort to manage these exposures, we utilize various financial derivative contracts which are intended to partially reduce the volatility in our adjusted funds flow. Contracts settled in the period result in realized gains or losses based on the market price compared to the contract price and the notional volume outstanding. Changes in the fair value of unsettled contracts are reported as unrealized gains or losses in the period as the forward markets for commodities and currencies fluctuate and as new contracts are executed. The following table summarizes the results of our financial derivative contracts for the years ended December 31, 2021 and 2020.

	Years Ended December 31		
($ thousands)	**2021**	2020	Change
Realized financial derivatives gain (loss)			
Crude oil	**$ (170,975)**	$ 48,495	$ (219,470)
Natural gas	**(13,266)**	138	(13,404)
Interest and financing	**—**	(797)	797
Total	**$ (184,241)**	$ 47,836	$ (232,077)
Unrealized financial derivatives gain (loss)			
Crude oil	**$ (105,492)**	$ (17,696)	$ (87,796)
Natural gas	**(5,749)**	282	(6,031)
Interest and financing	**—**	34	(34)
Equity total return swap	**7,610**	(1,120)	8,730
Total	**$ (103,631)**	$ (18,500)	$ (85,131)
Total financial derivatives gain (loss)			
Crude oil	**$ (276,467)**	$ 30,799	$ (307,266)
Natural gas	**(19,015)**	420	(19,435)
Interest and financing	**—**	(763)	763
Equity total return swap	**7,610**	(1,120)	8,730
Total	**$ (287,872)**	$ 29,336	$ (317,208)

We recorded total financial derivatives losses of $287.9 million for 2021 compared to a gain of $29.3 million for 2020. The realized financial derivatives loss for 2021 of $184.2 million was primarily a result of the market prices for crude oil settling at levels above those set in our derivative contracts outstanding during the year. The unrealized loss on financial derivatives of $103.6 million for 2021 was primarily a result of the increase in forecasted crude oil pricing used to revalue our crude oil contracts in place at December 31, 2021. The fair value of our financial derivative contracts resulted in a net liability of $125.4 million at December 31, 2021 compared to a net liability of $21.7 million at December 31, 2020.

Baytex had the following commodity financial derivative contracts as at February 24, 2022.

	Period	Volume	Price/Unit [1]	Index
Oil				
Basis swap	Jan 2022 to Dec 2022	12,000 bbl/d	WTI less US$12.40/bbl	WCS
Basis swap	Jan 2022 to Dec 2022	4,000 bbl/d	WTI less US$4.43/bbl	MSW
Basis swap[3]	Feb 2022 to Jun 2022	1,000 bbl/d	WTI less US$3.00/bbl	MSW
Basis swap[3]	Mar 2022 to Dec 2022	2,000 bbl/d	WTI less US$2.88/bbl	MSW
Fixed - Sell	Jan 2022 to Dec 2022	10,000 bbl/d	US$53.50/bbl	WTI
3-way option[2]	Jan 2022 to Dec 2022	1,500 bbl/d	US$40.00/US$50.00/US$58.10	WTI
3-way option[2]	Jan 2022 to Dec 2022	2,000 bbl/d	US$46.00/US$56.00/US$66.72	WTI
3-way option[2]	Jan 2022 to Dec 2022	2,500 bbl/d	US$47.00/US$57.00/US$67.00	WTI
3-way option[2]	Jan 2022 to Dec 2022	2,500 bbl/d	US$50.00/US$60.00/US$70.00	WTI
3-way option[2]	Jan 2022 to Dec 2022	2,000 bbl/d	US$53.00/US$63.50/US$72.90	WTI
3-way option[2]	Jan 2023 to Dec 2023	2,000 bbl/d	US$55.00/US$66.00/US$84.00	WTI
3-way option[2][3]	Jan 2023 to Dec 2023	2,500 bbl/d	US$60.00/US$75.00/US$91.54	WTI
Natural Gas				
Fixed - Sell	Jan 2022 to Dec 2022	5,000 GJ/d	$2.53/GJ	AECO 7A
Fixed - Sell	Jan 2022 to Dec 2022	14,250 GJ/d	$2.84/GJ	AECO 5A
Fixed - Sell	Jan 2022 to Dec 2022	1,000 mmbtu/d	US$2.94/mmbtu	NYMEX
3-way option[2]	Jan 2022 to Dec 2022	2,500 mmbtu/d	US$2.25/US$2.75/US$3.06	NYMEX
3-way option[2]	Jan 2022 to Dec 2022	1,500 mmbtu/d	US$2.60/US$2.91/US$3.56	NYMEX
3-way option[2]	Jan 2022 to Dec 2022	2,500 mmbtu/d	US$2.60/US$3.00/US$3.83	NYMEX
3-way option[2]	Jan 2022 to Dec 2022	2,500 mmbtu/d	US$2.65/US$2.90/US$3.40	NYMEX
3-way option[2]	Jan 2022 to Dec 2022	2,500 mmbtu/d	US$3.00/US$3.75/US$4.40	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$60.00/US$70.00 contract, Baytex receives WTI plus US$10.00/bbl when WTI is at or below US$50.00/bbl; Baytex receives US$60.00/bbl when WTI is between US$50.00/bbl and US$60.00/bbl; Baytex receives the market price when WTI is between US$60.00/bbl and US$70.00/bbl; and Baytex receives US$70.00/bbl when WTI is above US$70.00/bbl.*
(3) *Contracts entered subsequent to December 31, 2021.*

Operating Netback

The following table summarizes our operating netback on a per boe basis for our Canadian and U.S. operations for the years ended December 31, 2021 and 2020.

	Years Ended December 31					
	2021			2020		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**49,424**	**30,731**	**80,156**	48,602	31,179	79,781
Operating netback:						
Total sales, net of blending and other expense[1]	**$ 57.79**	**$ 65.98**	**$ 60.93**	$ 29.42	$ 35.38	$ 31.75
Less:						
Royalties[2]	**(6.72)**	**(19.42)**	**(11.59)**	(2.59)	(10.31)	(5.61)
Operating expense[2]	**(14.28)**	**(7.61)**	**(11.72)**	(13.89)	(7.39)	(11.35)
Transportation expense[2]	**(1.79)**	**—**	**(1.10)**	(1.60)	—	(0.97)
Operating netback[1]	**$ 35.00**	**$ 38.95**	**$ 36.52**	$ 11.34	$ 17.68	$ 13.82
Realized financial derivatives gain (loss)[3]	**—**	**—**	**(6.30)**	—	—	1.64
Operating netback after financial derivatives[1]	**$ 35.00**	**$ 38.95**	**$ 30.22**	$ 11.34	$ 17.68	$ 15.46

(1) *Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.*
(2) *Refer to Royalties, Operating Expense and Transportation Expense sections in this MD&A for a description of the composition these measures.*
(3) *Calculated as realized financial derivatives gain (loss) expense divided by barrels of oil equivalent production volume for the applicable period.*

Our operating netback[1] of $36.52/boe for 2021 was higher than $13.82/boe for 2020 due to an increase in North American benchmark prices which resulted in higher per units sales, net of royalties. Total operating expense of $11.72/boe and transportation expense of $1.10/boe for 2021 were slightly higher than $11.35/boe and $0.97/boe in 2020. Including realized gains and losses on financial derivatives our operating netback was $30.22/boe for 2021 compared to $15.46/boe for 2020.

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

General and Administrative Expense

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

The following table summarizes our G&A expense for the years ended December 31, 2021 and 2020.

	Years Ended December 31		
($ thousands except for per boe)	**2021**	2020	Change
Gross general and administrative expense	**$ 44,368**	$ 37,217	$ 7,151
Overhead recoveries	**(3,564)**	(2,949)	(615)
General and administrative expense	**$ 40,804**	$ 34,268	$ 6,536
General and administrative expense per boe[1]	**$ 1.39**	$ 1.17	$ 0.22

(1) General and administrative expense per boe is calculated as general and administrative expense divided by barrels of oil equivalent production volume for the applicable period.

G&A expense was $40.8 million ($1.39/boe) for 2021 compared to $34.3 million ($1.17/boe) for 2020. G&A expense was $6.5 million higher relative to 2020 as employee and director compensation was reduced from Q2/2020 to Q4/2020 and we received benefits under the Canadian Emergency Wage Subsidy program in 2020. G&A expense of $40.8 million ($1.39/boe) for 2021 was consistent with expectations and was slightly below our revised annual guidance of $42 million ($1.44/boe). We expect annual G&A expense of $43 million ($1.45/boe) for 2022.

Financing and Interest Expense

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

The following table summarizes our financing and interest expense for the years ended December 31, 2021 and 2020.

	Years Ended December 31		
($ thousands except for per boe)	**2021**	2020	Change
Interest on credit facilities	**$ 13,300**	$ 15,256	$ (1,956)
Interest on long-term notes	**78,546**	90,830	(12,284)
Interest on lease obligations	**223**	448	(225)
Cash interest	**$ 92,069**	$ 106,534	$ (14,465)
Amortization of debt issue costs	**4,858**	6,617	(1,759)
Accretion of asset retirement obligations	**12,381**	8,978	3,403
Early redemption expense	**$ 1,851**	$ 3,312	(1,461)
Financing and interest expense	**$ 111,159**	$ 125,441	$ (14,282)
Cash interest per boe[1]	**$ 3.15**	$ 3.65	$ (0.50)
Financing and interest expense per boe[1]	**$ 3.80**	$ 4.30	$ (0.50)

(1) Calculated as cash interest or financing and interest expense divided by barrels of oil equivalent production volume for the applicable period.

Financing and interest expense was $111.2 million ($3.80/boe) in 2021 compared to $125.4 million ($4.30/boe) in 2020.

Cash interest of $92.1 million ($3.15/boe) in 2021 was lower than $106.5 million ($3.65/boe) in 2020 as we reduced our debt to $1.4 billion at December 31, 2021 compared to $1.8 billion at December 31, 2020. Interest on our credit facilities was lower due to lower borrowings and a lower weighted average borrowing rate on amounts outstanding in 2021 relative to 2020. The weighted average interest rate on our credit facilities was 2.1% in 2021 compared to 2.4% in 2020. Interest on our long-term notes was lower in 2021 as the average principal amount outstanding was lower as we repurchased and redeemed US$200.0 million of the 5.625% Notes in 2021.

Financing and interest expense for 2021 includes the accelerated amortization of debt issue costs and $1.9 million of early redemption expense associated with the redemption of US$200 million principal amount of the 5.625% Notes in 2021. Accretion of asset retirement obligations of $12.4 million for 2021 was higher than $9.0 million for 2020 due to a higher discount rate for 2021 relative to 2020.

Cash interest of $92.1 million ($3.15/boe) for 2021 was consistent with our annual guidance of $92.0 million ($3.16/boe). We expect annual cash interest to be $80.0 million ($2.70/boe) for 2022 as we continue to reduce the amount of debt in our capital structure.

Exploration and Evaluation Expense

Exploration and evaluation ("E&E") expense is related to the expiry of leases and the de-recognition of costs for exploration programs that have not demonstrated commercial viability and technical feasibility. E&E expense will vary depending on the timing of expiring leases, the accumulated costs of the expiring leases and the economic facts and circumstances related to the Company's exploration programs. E&E expense was $15.2 million for 2021 which is consistent with $14.0 million for 2020.

Depletion and Depreciation

Depletion and depreciation expense varies with the carrying amount of the Company's oil and gas properties, the amount of proved plus probable reserves volumes and the rate of production for the period. The following table summarizes depletion and depreciation expense for the years ended December 31, 2021 and 2020.

	Years Ended December 31		
($ thousands except for per boe)	**2021**	2020	Change
Depletion	**$ 458,941**	$ 478,859	$ (19,918)
Depreciation	**5,639**	7,521	(1,882)
Depletion and depreciation	**$ 464,580**	$ 486,380	$ (21,800)
Depletion and depreciation per boe[1]	**$ 15.88**	$ 16.66	$ (0.78)

(1) Depletion and depreciation expense per boe is calculated as depletion and depreciation expense divided by barrels of oil equivalent production volume for the applicable period.

Depletion and depreciation expense was $464.6 million ($15.88/boe) for 2021 compared to $486.4 million ($16.66/boe) reported for 2020. Total depletion and depreciation expense as well as the depletion rate per boe were lower in 2021 relative to 2020 as the Company recorded a $2.2 billion impairment loss on our oil and gas properties in 2020 which reduced the depletable base of our oil and gas properties for 2021 despite the $1.5 billion impairment reversals recorded for the year ended December 31, 2021.

Impairment

2021 Impairment Reversals

During 2021, we identified indicators of impairment reversal for oil and gas properties in each of our six CGU's due to the increase in forecasted commodity prices.

At December 31, 2021, utilizing updated development plans and changes to commodity prices we estimated the recoverable amount of oil and gas properties in five CGUs. We recorded an impairment reversal of $416.0 million as the estimated recoverable amount in three of our CGUs exceeded their carrying value. No indicators of impairment or impairment reversal were identified for the Company's E&E assets at December 31, 2021.

At December 31, 2021, the recoverable amount of five CGUs was calculated using the following benchmark reference prices for the years 2022 to 2031 adjusted for differentials specific to each CGU. The prices and costs subsequent to 2031 have been adjusted for inflation at an annual rate of 2.0%.

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
WTI crude oil (US$/bbl)	72.83	68.78	66.76	68.09	69.45	70.84	72.26	73.70	75.18	76.68
WCS heavy oil ($/bbl)	74.42	69.17	66.54	67.87	69.23	70.61	72.02	73.46	74.69	76.19
LLS crude oil (US$/bbl)	74.33	70.28	68.27	69.62	71.01	72.41	73.85	75.32	76.82	78.35
Edmonton par oil ($/bbl)	86.82	80.73	78.01	79.57	81.16	82.78	84.44	86.13	87.85	89.61
Henry Hub gas (US$/mmbtu)	3.85	3.44	3.17	3.24	3.30	3.37	3.44	3.50	3.58	3.65
AECO gas ($/mmbtu)	3.56	3.21	3.05	3.11	3.17	3.23	3.30	3.36	3.43	3.50
Exchange rate (CAD/USD)	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26

The following table summarizes the recoverable amount and impairment reversal at December 31, 2021 and demonstrates the sensitivity of the estimated recoverable amount of the five CGUs tested for impairment reversal with respect to reasonably possible changes in key assumptions inherent in the estimate.

	Recoverable amount	Impairment Reversal	Change in discount rate of 1%	Change in oil price of $2.50/bbl	Change in gas price of $0.25/mcf
Conventional CGU	$ 77,846	$ 19,000	$ —	$ 3,000	$ 8,000
Peace River CGU	489,274	251,000	8,500	53,000	3,500
Lloydminster CGU	479,411	146,000	12,500	52,000	—
Viking CGU	1,320,094	—	38,000	85,500	4,500
Eagle Ford CGU	2,008,478	—	97,200	138,800	31,300
	$ 4,375,103	$ 416,000	$ 156,200	$ 332,300	$ 47,300

At June 30, 2021, we identified indicators of impairment reversal for oil and gas properties in each of our six CGU's due to the increase in forecasted commodity prices. We recorded an impairment reversal of $1.1 billion as the estimated recoverable amount of all six CGUs exceeded their carrying value. No indicators of impairment or impairment reversal were identified for the Company's E&E assets at June 30, 2021.

At June 30, 2021, the recoverable amount of the Company's CGUs were calculated using the following benchmark reference prices for the years 2021 to 2030 adjusted for commodity differentials specific to the Company. The prices and costs subsequent to 2030 have been adjusted for inflation at an annual rate of 2.0%.

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
WTI crude oil (US$/bbl)	71.33	67.20	63.95	63.23	64.50	65.79	67.10	68.44	69.81	71.21
WCS heavy oil ($/bbl)	72.22	66.84	61.73	60.70	61.91	63.15	64.42	65.70	67.02	68.36
LLS crude oil (US$/bbl)	72.17	68.53	65.80	65.10	66.39	67.71	69.05	70.42	71.82	73.26
Edmonton par oil ($/bbl)	83.20	78.27	74.06	73.05	74.51	76.00	77.52	79.07	80.66	82.27
Henry Hub gas (US$/mmbtu)	3.42	3.19	2.92	2.96	3.02	3.08	3.14	3.21	3.27	3.34
AECO gas ($/mmbtu)	3.46	3.13	2.72	2.71	2.76	2.82	2.88	2.94	2.99	3.05
Exchange rate (CAD/USD)	1.24	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25

The following table summarizes the recoverable amount and impairment reversal at June 30, 2021 and demonstrates the sensitivity of the estimated recoverable amount of the Company's CGUs comprising oil and gas properties to reasonably possible changes in key assumptions inherent in the estimate.

	Recoverable amount	Impairment Reversal	Change in discount rate of 1%	Change in oil price of $2.50/bbl	Change in gas price of $0.25/mcf
Conventional CGU	$ 57,891	$ 15,000	$ 1,000	$ 1,000	$ 8,000
Peace River CGU	238,714	154,000	4,000	40,000	2,500
Lloydminster CGU	340,730	154,000	12,500	52,000	—
Duvernay CGU(1)	115,157	5,000	45,000	44,500	44,500
Viking CGU	1,338,985	356,000	47,000	89,500	4,500
Eagle Ford CGU	2,015,118	442,415	109,400	103,900	24,400
	$ 4,106,595	$ 1,126,415	$ 218,900	$ 330,900	$ 83,900

(1) The impairment reversal for the Duvernay CGU was limited to total accumulated impairments less subsequent depletion of $5.0 million.

2020 Impairments

We recorded total net impairments of $2.4 billion for the year ended December 31, 2020 due to significant changes in forecasted commodity prices caused by the COVID-19 pandemic and OPEC+ price war.

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

At December 31, 2020, with updated development plans, including capital efficiencies and reduced well costs, reflected in our reserves along with changes in commodity prices, we estimated the recoverable amount for E&E assets and oil and gas properties in each of our six CGUs. We recorded an impairment reversal of $356.1 million at December 31, 2020 as the estimated recoverable amount of the Viking and Eagle Ford CGUs exceeded their carrying value. The total impairment reversal recorded at Q4/2020 includes $341.3 million related to oil and gas properties and $14.8 million related to E&E assets.

Share-Based Compensation Expense

Share-based compensation ("SBC") expense includes expense associated with our Share Award Incentive Plan, Incentive Award Plan, and Deferred Share Unit Plan and includes gains or losses on equity total return swaps used to fix the aggregate cost of new grants made under the Incentive Award Plan and the Deferred Share Unit Plan. SBC expense varies from period to period depending on the fair value assigned to new grants and the number of unvested awards or units outstanding.

We recorded SBC expense of $11.1 million for 2021 which is higher than $9.5 million reported for 2020. The total expense for 2021 is comprised of non-cash compensation expense of $6.4 million related to the Share Award Incentive Plan compared to $7.2 million in 2020. SBC expense for 2021 also included cash compensation expense of $4.7 million related to the Incentive Award Plan and Deferred Unit Share Plan compared to $2.3 million in 2020.

Foreign Exchange

Unrealized foreign exchange gains and losses are primarily a result of changes in the reported amount of our U.S. dollar denominated long-term notes and our U.S. dollar denominated intercompany notes issued in 2020. The long-term notes and intercompany notes are translated to Canadian dollars on the balance sheet date using the closing CAD/USD exchange rate resulting in unrealized gains and losses. Realized foreign exchange gains and losses are due to day-to-day U.S. dollar denominated transactions occurring in our Canadian functional currency entities.

($ thousands except for exchange rates)	Years Ended December 31 2021	2020	Change
Unrealized foreign exchange (gain) loss	**$ (1,905)**	$ 9,232	$ (11,137)
Realized foreign exchange gain	**(963)**	(544)	(419)
Foreign exchange (gain) loss	**$ (2,868)**	$ 8,688	$ (11,556)
CAD/USD exchange rates:			
At beginning of period	**1.2755**	1.2965	
At end of period	**1.2656**	1.2755	

We recorded a foreign exchange gain of $2.9 million for 2021 compared to a loss of $8.7 million for 2020. Unrealized foreign exchange gains $1.9 million for 2021 relate to the remeasurement of our long-term notes, intercompany notes and credit facilities due to changes in the value of the Canadian dollar relative to the U.S. dollar at December 31, 2021 compared to December 31, 2020. Realized foreign exchange gains and losses will fluctuate depending on the amount and timing of day-to-day U.S. dollar denominated transactions for our Canadian operations. We recorded a realized foreign exchange gain of $1.0 million for 2021 compared to a gain of $0.5 million for 2020.

Income Taxes

($ thousands)	Years Ended December 31 2021	2020	Change
Current income tax expense	**$ 1,272**	$ 574	$ 698
Deferred income tax expense (recovery)	**79,968**	(160,967)	240,935
Total income tax expense (recovery)	**$ 81,240**	$ (160,393)	$ 241,633

Current income tax expense was $1.3 million for 2021 compared to $0.6 million recorded in 2020. Current income tax is higher in 2021 due to higher state tax owed on our U.S. operations.

We recorded a deferred income tax expense of $80.0 million for 2021 compared to a recovery of $161.0 million for 2020. The deferred income tax expense in 2021 is primarily related to the impairment reversals recorded in 2021 whereas the deferred tax recovery recorded in 2020 is primarily related to the impairment loss recorded in 2020.

As disclosed in the 2020 annual financial statements, certain indirect subsidiaries received reassessments from the Canada Revenue Agency (the "CRA") that deny $591.0 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, 2021**	December 31, 2020
Canadian oil and natural gas property expenditures	**$ 406,475**	$ 449,670
Canadian development expenditures	**480,814**	557,554
Canadian exploration expenditures	**—**	10,907
Undepreciated capital costs	**287,170**	347,297
Non-capital losses	**996,556**	1,015,152
Financing costs and other	**12,835**	14,780
Total Canadian tax pools	**$ 2,183,850**	$ 2,395,360

U.S. Tax Pools *($ thousands)*		
Depletion	**$ 136,505**	$ 147,160
Intangible drilling costs	**1,898**	5,521
Tangibles	**23,949**	39,028
Net operating losses	**992,258**	1,150,068
Other	**152,509**	192,495
Total U.S. tax pools	**$ 1,307,119**	$ 1,534,272

Net Income (Loss)

Net income or loss for the years ended December 31, 2021 and 2020 are set forth in the following table.

	Years Ended December 31		
($ thousands)	**2021**	2020	Change
Petroleum and natural gas sales	**$ 1,868,195**	$ 975,477	$ 892,718
Royalties	**(339,156)**	(163,735)	(175,421)
Revenue, net of royalties	**1,529,039**	811,742	717,297
Expenses			
Operating	**(343,002)**	(331,345)	(11,657)
Transportation	**(32,261)**	(28,437)	(3,824)
Blending and other	**(85,689)**	(48,381)	(37,308)
Operating netback (1)	**$ 1,068,087**	$ 403,579	$ 664,508
General and administrative	**(40,804)**	(34,268)	(6,536)
Cash interest	**(92,069)**	(106,534)	14,465
Realized financial derivative (loss) gain	**(184,241)**	47,836	(232,077)
Realized foreign exchange gain	**963**	544	419
Other (expense) income	**(295)**	3,176	(3,471)
Current income tax expense	**(1,272)**	(574)	(698)
Share-based compensation - cash	**(4,741)**	(2,253)	(2,488)
Adjusted funds flow (2)	**$ 745,628**	$ 311,506	$ 434,122
Exploration and evaluation	**(15,212)**	(14,011)	(1,201)
Depletion and depreciation	**(464,580)**	(486,380)	21,800
Share-based compensation - non-cash	**(6,389)**	(7,216)	827
Non-cash financing, accretion and early redemption expense	**(19,090)**	(18,907)	(183)
Non-cash other income	**2,857**	2,128	729
Unrealized financial derivatives loss	**(103,631)**	(18,500)	(85,131)
Unrealized foreign exchange gain (loss)	**1,905**	(9,232)	11,137
Gain on dispositions	**9,666**	901	8,765
Impairment reversals (expense)	**1,542,414**	(2,360,220)	3,902,634
Deferred income tax (expense) recovery	**(79,968)**	160,967	(240,935)
Net income (loss)	**$ 1,613,600**	$ (2,438,964)	$ 4,052,564

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

We generated adjusted funds flow of $745.6 million for 2021 compared to $311.5 million for 2020. The $434.1 million increase in adjusted funds flow for 2021 is primarily due to improvements in commodity benchmark prices, which resulted in a $664.5 million increase in operating netback partially offset by a $232.1 million increase in realized financial derivative losses.

We reported net income of $1.6 billion for 2021 compared to a net loss of $2.4 billion for 2020. The increase in net income for 2021 was primarily the result of impairment reversals of $1.2 billion net of tax compared to impairment losses of $1.8 billion net of tax recorded in 2020. Net income in 2021 also reflects the $434.1 million increase in adjusted funds flow relative to 2020.

Other Comprehensive Income (Loss)

Other comprehensive income or loss is comprised of the foreign currency translation adjustment on U.S. net assets which includes a series of intercompany debt instruments outstanding between our Canadian and U.S. subsidiaries. Foreign exchange gains or losses on the debt owing from the U.S. subsidiary is recorded in other comprehensive income and the offsetting foreign exchange gain or loss on debt owed to the Canadian subsidiary is included in profit and loss for the period.

The foreign currency translation gain of $13.1 million for 2021 relates to the change in value of our U.S. net assets and intercompany notes which are expressed in Canadian dollars and are influenced by changes in the value of the Canadian dollar relative to the U.S. dollar at December 31, 2021 compared to December 31, 2020. The CAD/USD exchange rate was 1.2656 CAD/USD at December 31, 2021 compared to 1.2755 CAD/USD at December 31, 2020. Impairment reversals of US$362 million at Q2/2021 increased the value of our U.S. net assets which further contributed to the foreign currency translation gain for 2021.

Capital Expenditures

Capital expenditures for the years ended December 31, 2021 and 2020 are summarized as follows.

	Years Ended December 31					
	2021			2020		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 182,761**	**$ 102,985**	**$ 285,746**	$ 143,013	$ 104,599	$ 247,612
Facilities	**18,213**	**924**	**19,137**	26,043	21	26,064
Land, seismic and other	**7,236**	**1,184**	**8,420**	5,896	768	6,664
Exploration and development expenditures	**$ 208,210**	**$ 105,093**	**$ 313,303**	$ 174,952	$ 105,388	$ 280,340
Property acquisitions	**$ 1,557**	**$ —**	**$ 1,557**	$ —	$ —	$ —
Proceeds from dispositions	**$ (7,211)**	**$ (593)**	**$ (7,804)**	$ (182)	$ —	$ (182)

Exploration and development expenditures were $313.3 million for 2021 compared to $280.3 million for 2020. Expenditures were higher in 2021 compared to 2020 after we reset our development programs in the U.S. and Canada in response to the volatility in crude oil prices throughout 2020. We resumed development activity in Q4/2020 as commodity prices stabilized and have maintained the pace of development throughout 2021.

In Canada, we invested $208.2 million on exploration and development expenditures in 2021 which is $33.3 million higher than $175.0 million in 2020 as we resumed development operations in Q4/2020 and maintained the pace of development throughout 2021. Exploration and development expenditures in 2021 include costs associated with drilling 125 (123.2 net) light oil wells, 37 (33.5 net) heavy oil wells, 2 (2.0 net) conventional natural gas wells and investing $18.2 million on facilities. Exploration and development expenditures of $175.0 million for 2020 include costs associated with drilling 104 (101.2 net) light oil wells, 33 (33.0 net) heavy oil wells, 2 (2.0 net) conventional natural gas wells, 6 (6.0 net) stratigraphic exploration wells, along with $26.0 million on facilities.

Total U.S. exploration and development expenditures were $105.1 million for 2021 which is $0.3 million lower than $105.4 million for 2020. Exploration and development expenditures of $105.1 million for 2021 include costs associated with the drilling of 67 (15.5 net) wells along with completing 93 (23.1 net) wells that were brought on production. Reduced well costs and a stronger Canadian dollar in 2021 resulted in exploration and development expenditures that were lower than 2020 when we spent $105.4 million and drilled 65 (16.3 net) wells and brought 62 (14.1 net) wells on production.

We completed minor acquisitions in 2021 for consideration of $1.6 million and dispositions for proceeds of $7.8 million. In 2020 we completed minor dispositions of $0.2 million.

Total exploration and development expenditures of $313.3 million for 2021 was in line with our annual guidance range of $285 - $315 million. We expect annual exploration and development expenditures of $400 - $450 million for 2022 which reflects additional activity and Clearwater development relative to 2021.

CAPITAL RESOURCES AND LIQUIDITY

Our capital management objective is to maintain financial flexibility 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, 2021, our capital structure was comprised of shareholders' capital, long-term notes, trade and other receivables, trade and other payables and the credit facilities.

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.

The capital intensive nature of our operations requires the maintenance of 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.

Management of debt levels is a priority for Baytex in order to sustain operations and support long-term plans. At December 31, 2021, net debt(1) of $1.41 billion was $437.9 million lower than $1.85 billion at December 31, 2020. The decrease in net debt is primarily a result of free cash flow(2) of $421.3 million generated during 2021 being allocated to debt repayment.

We monitor our capital structure and liquidity requirements using a net debt to adjusted funds flow ratio calculated on a trailing twelve month basis. At December 31, 2021, our net debt to adjusted funds flow ratio(1) was 1.9 compared to a ratio of 5.9 as at December 31, 2020. The decrease in the net debt to adjusted funds flow ratio relative to December 31, 2020 is attributed to higher adjusted funds flow during 2021 and lower net debt at December 31, 2021 as our priority was to direct free cash flow to debt repayment.

Credit Facilities

Our credit facilities include US$575 million of revolving credit facilities and a $300 million non-revolving term loan (collectively, the "Credit Facilities"). Our Credit Facilities mature on April 2, 2024 and 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. At December 31, 2021, we had $521.5 million of borrowings and letters of credit outstanding under our Credit Facilities that total approximately $1.0 billion.

The Credit Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The Credit Facilities contain standard commercial covenants in addition to the financial covenants detailed below. There are no mandatory principal payments required prior to maturity which could be extended upon our request. Advances (including letters of credit) under the Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank’s prime lending rate, bankers’ acceptance discount rates or London Interbank Offered Rates ("LIBOR"), plus applicable margins.

The LIBOR benchmark transition begins on December 31, 2021. Certain tenors of the U.S. dollar LIBOR benchmark will no longer be published as of December 31, 2021 while some tenors will continue to be published through mid-2023. We expect the U.S. dollar LIBOR benchmarks to be replaced with an alternative that will apply to our U.S. dollar borrowing at our option. We do not expect this change to have a material impact to Baytex as U.S. dollar borrowings under the credit facilities can also bear interest at the U.S. base loan rate.

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

The weighted average interest rate on the Credit Facilities was 2.1% for 2021 as compared to 2.4% for 2020.

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

Financial Covenants

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at December 31, 2021.

Covenant Description	Position as at December 31, 2021	Covenant
Senior Secured Debt(1) to Bank EBITDA(2) (Maximum Ratio)	**0.6:1.0**	3.5:1.0
Interest Coverage(3) (Minimum Ratio)	**9.1:1.0**	2.0:1.0

(1) "Senior Secured Debt" is calculated in accordance with the credit facility agreements and is defined as the principal amount of the Credit Facilities and other secured obligations identified in the credit agreement. As at December 31, 2021, the Company's Senior Secured Debt totaled $521.5 million.
(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 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, 2021 was $836.9 million.
(3) "Interest coverage" is calculated in accordance with the credit agreement and is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis. Financing and interest expenses for the twelve months ended December 31, 2021 were $91.8 million.

Long-Term Notes

We have two series of long-term notes outstanding with a total principal amount of $885.9 million as at December 31, 2021. The long-term notes do not contain any financial maintenance covenants.

On June 6, 2014, we issued US$800 million of senior unsecured notes, comprised of US$400 million of 5.125% notes due June 1, 2021 (the "5.125% Notes"), which were redeemed February 20, 2020, and US$400 million of 5.625% notes due June 1, 2024 (the "5.625% Notes"). The 5.625% Notes pay interest semi-annually with the principal amount repayable at maturity. The 5.625% Notes are redeemable at our option, in whole or in part, at 100.938% and will be redeemable at par from June 1, 2022 to maturity. During 2021, Baytex repurchased and cancelled a total of US$200.0 million of the 5.625% Notes and recorded early redemption expense of $1.9 million. As at December 31, 2021, there was US$200.0 million of the 5.625% Notes outstanding.

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

Shareholders' Capital

We are authorized to issue an unlimited number of common shares and 10.0 million preferred shares. The rights and terms of preferred shares are determined upon issuance. During the year ended December 31, 2021, we issued 3.0 million common shares pursuant to our share-based compensation program. As at February 24, 2022, we had 564.2 million common shares issued and outstanding and no preferred shares issued and outstanding.

Contractual Obligations

We have a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact our adjusted funds flow in an ongoing manner. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of December 31, 2021 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	**$ 190,692**	$ 190,692	$ —	$ —	$ —
Financial derivatives	**134,020**	134,020	—	—	—
Credit facilities - principal (1) (2)	**506,514**	—	506,514	—	—
Total long-term notes - principal (2)	**885,920**	—	253,120	—	632,800
Interest on long-term notes (3)	**325,172**	69,608	130,868	110,740	13,956
Lease obligations (2)	**8,014**	3,068	3,989	902	55
Processing agreements	**6,090**	753	890	530	3,917
Transportation agreements	**81,182**	20,500	37,825	14,673	8,184
Total	**$ 2,137,604**	$ 418,641	$ 933,206	$ 126,845	$ 658,912

(1) The credit facilities mature on April 2, 2024. Maturity will automatically be extended to June 4, 2024 providing Baytex has either refinanced, or has the ability to repay, the outstanding 2024 long-term notes with existing credit capacity as of April 1, 2024.
(2) Principal amount of instruments.
(3) Excludes interest on our credit facilities as interest payments fluctuate based on a floating rate of interest and changes in the outstanding balances.

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

FOURTH QUARTER OPERATING AND FINANCIAL RESULTS

	Three Months Ended December 31					
	2021			2020		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total daily production						
Light oil and condensate (bbl/d)	**16,388**	**18,598**	**34,986**	15,212	14,356	29,568
Heavy oil (bbl/d)	**23,482**	**—**	**23,482**	21,725	—	21,725
NGL (bbl/d)	**1,713**	**6,271**	**7,984**	1,364	5,131	6,495
Total liquids (bbl/d)	**41,583**	**24,869**	**66,452**	38,301	19,487	57,788
Natural gas (mcf/d)	**52,673**	**33,356**	**86,029**	42,117	33,999	76,116
Total production (boe/d)	**50,362**	**30,428**	**80,789**	45,321	25,154	70,475
Operating netback ($/boe)						
Light oil and condensate ($/bbl) (1)	**$ 91.17**	**$ 97.68**	**$ 94.63**	$ 47.43	$ 52.73	$ 50.00
Heavy oil, net of blending and other expense ($/bbl) (2)	**67.76**	**—**	**67.76**	27.87	—	27.87
NGL ($/bbl) (1)	**41.73**	**39.42**	**39.92**	16.57	19.18	18.63
Natural gas ($/mcf) (1)	**4.65**	**6.70**	**5.44**	2.50	3.26	2.84
Total sales, net of blending and other per boe (2)	**67.54**	**75.17**	**70.42**	32.10	38.41	34.35
Royalties per boe (3)	**(8.15)**	**(22.28)**	**(13.47)**	(2.90)	(11.11)	(5.83)
Operating expense per boe (3)	**(15.37)**	**(8.63)**	**(12.83)**	(14.73)	(7.92)	(12.30)
Transportation expense per boe (3)	**(1.76)**	**—**	**(1.10)**	(1.60)	—	(1.03)
Operating netback per boe (1)	**$ 42.26**	**$ 44.26**	**$ 43.02**	$ 12.87	$ 19.38	$ 15.19
Financial						
Petroleum and natural gas sales	**$ 341,966**	**$ 210,437**	**$ 552,403**	$ 144,741	$ 88,895	$ 233,636
Royalties	**(37,770)**	**(62,382)**	**(100,152)**	(12,092)	(25,715)	(37,807)
Revenue, net of royalties	**304,196**	**148,055**	**452,251**	132,649	63,180	195,829
Operating	**(71,203)**	**(24,154)**	**(95,357)**	(61,409)	(18,339)	(79,748)
Transportation	**(8,169)**	**—**	**(8,169)**	(6,692)	—	(6,692)
Blending and other	**(29,021)**	**—**	**(29,021)**	(10,891)	—	(10,891)
Operating netback (2)	**$ 195,803**	**$ 123,901**	**$ 319,704**	$ 53,657	$ 44,841	$ 98,498
General and administrative	**—**	**—**	**(11,481)**	—	—	(9,314)
Cash interest	**—**	**—**	**(21,319)**	—	—	(25,194)
Realized financial derivatives (loss) gain	**—**	**—**	**(70,544)**	—	—	17,105
Other	**—**	**—**	**(1,594)**	—	306	1,081
Adjusted funds flow (4)	**$ 195,803**	**$ 123,901**	**$ 214,766**	$ 53,657	$ 45,147	$ 82,176
Net income	**$ 526,412**	**$ 72,457**	**$ 563,239**	$ 112,954	$ 144,200	$ 221,160
Exploration and development expenditures	**$ 59,821**	**$ 14,174**	**$ 73,995**	$ 45,030	$ 32,779	$ 77,809
Property acquisitions	**$ 1,443**	**$ —**	**$ 1,443**	$ —	$ —	$ —
Proceeds from dispositions	**$ (6,857)**	**$ —**	**$ (6,857)**	$ (33)	$ —	$ (33)
Net debt (4)			**$1,409,717**			$1,847,601

(1) Calculated as light oil and condensate, NGL or natural gas sales divided by barrels of oil equivalent production volume for the applicable period.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.
(3) Calculated as royalties, operating or transportation expense divided by barrels of oil equivalent production volume for the applicable period.
(4) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

	Three Months Ended December 31		
	2021	2020	Change
Benchmark Averages			
WTI oil (US$/bbl) [(1)]	**77.19**	42.66	34.53
MEH oil (US$/bbl) [(2)]	**78.89**	43.05	35.84
MEH oil differential to WTI (US$/bbl)	**1.70**	0.39	1.31
Edmonton par oil ($/bbl) [(3)]	**93.29**	50.24	43.05
Edmonton par oil differential to WTI (US$/bbl)	**(3.15)**	(4.11)	0.96
WCS heavy oil ($/bbl) [(4)]	**78.82**	43.46	35.36
WCS heavy oil differential to WTI (US$/bbl)	**(14.63)**	(9.31)	(5.32)
AECO natural gas price ($/mcf) [(5)]	**4.94**	2.77	2.17
NYMEX natural gas price (US$/mmbtu) [(6)]	**5.83**	2.66	3.17
CAD/USD average exchange rate	**1.2600**	1.3031	(0.0431)

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

Our operating and financial results for Q4/2021 reflect the successful execution of our 2021 development programs and strong benchmark commodity prices. We invested $74.0 million on exploration and development expenditures in Q4/2021 and delivered production of 80,789 boe/d. Free cash flow[(1)] was $137.1 million in Q4/2021 which reflects strong commodity prices and the disciplined execution of our development programs.

In Canada, production averaged 50,362 boe/d in Q4/2021 which was 5,041 boe/d higher than 45,321 boe/d reported for Q4/2020 as a result of higher development activity in 2021 relative to 2020. Strong benchmark pricing resulted in our realized price of $67.54/boe for Q4/2021 which was $35.44/boe higher than $32.10/boe for Q4/2020. In Q4/2021, the Edmonton Par benchmark was $93.29/bbl and the WCS heavy oil price was $78.82/bbl compared to $50.24/bbl and $43.46/bbl for the same period of 2020, respectively. As a result of higher production and benchmark pricing, we generated operating netback[(1)] of $195.8 million ($42.26/boe) for Q4/2021 which was $142.1 million ($29.39/boe) higher than $53.7 million ($12.87/boe) reported for Q4/2020. Exploration and development expenditures of $59.8 million in Q4/2021 includes drilling and completion costs associated with 57 (57.0 net) wells compared to 32 (32.0 net) wells in Q4/2020 when we spent $45.0 million.

In the U.S., production averaged 30,428 boe/d for Q4/2021 which is 5,274 boe/d higher than 25,154 boe/d reported for Q4/2020. The increase in production was a result of higher completion activity on our lands in 2021 relative to 2020 when exploration and development activities were limited. The increase in benchmark commodity prices resulted in our realized price of $75.17/boe which was $36.76/boe higher than our realized price of $38.41/boe in Q4/2020. The MEH benchmark averaged US$78.89/bbl in Q4/2021 which was US$35.84/boe higher than US$43.05/bbl during Q4/2020. Operating netback of $123.9 million ($44.26/boe) was $79.1 million ($24.88/boe) higher than $44.8 million ($19.38/boe) for Q4/2020 due to higher benchmark prices and higher production in Q4/2021. Exploration and development expenditures of $14.2 million in Q4/2021 includes costs associated with drilling 15 (4.4 net) wells and commencing production from 14 (2.5 net) wells. Exploration and development expenditures were lower in Q4/2021 due to the timing of drilling and completion activity relative to Q4/2020 when we spent $32.8 million and drilled 26 (7.1 net) wells and brought 9 (2.7 net) wells on production.

We generated adjusted funds flow[(2)] of $214.8 million in Q4/2021 which is $132.6 million higher than $82.2 million in Q4/2020. The increase in adjusted funds flow in Q4/2021 is due to higher realized pricing driven by an increase in benchmark pricing along with higher production. Production of 80,789 boe/d in Q4/2021 was higher than 70,475 boe/d for Q4/2020 as development activity was limited during 2020 and was restarted late in 2020 and continued throughout 2021. Operating netback[(1)] of $43.02/boe in Q4/2021 is $27.83/boe higher than $15.19/boe in Q4/2020 and reflects higher benchmark prices. The increase in our realized price combined with the impact of higher production resulted in an $221.2 million increase in operating netback in Q4/2021 compared to Q4/2020. We recorded realized financial derivatives losses of $70.5 million in Q4/2021 compared to gains of $17.1 million in Q4/2020. G&A expense of $11.5 million in Q4/2021 was higher than $9.3 million in Q4/2020 when director and employee compensation was reduced by 10%. Interest expense of $21.3 million in Q4/2021 was $3.9 million lower than $25.2 million for Q4/2020 due to a decrease in our net debt[(2)] and a decrease in our long-term notes outstanding following the redemption of US$200.0 million of our 5.625% Notes during 2021. Net debt decreased from $1.85 billion in Q4/2020 to $1.41 billion in Q4/2021 as free cash flow generated in 2021 was used to reduce net debt.

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

We recorded net income of $563.2 million in Q4/2021 compared to $221.2 million in Q4/2020. The increase in net income for Q4/2021 relative to Q4/2020 is primarily a result of the improvement in commodity benchmark prices. Net income for Q4/2021 includes $416.0 million of impairment reversals due to improvements in forecasted commodity prices while Q4/2020 includes $341.3 million of impairment reversals.

QUARTERLY FINANCIAL INFORMATION

	2021				2020			
($ thousands, except per common share amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Petroleum and natural gas sales	**552,403**	488,736	442,354	384,702	233,636	252,538	152,689	336,614
Net income (loss)	**563,239**	32,714	1,052,999	(35,352)	221,160	(23,444)	(138,463)	(2,498,217)
Per common share - basic	**1.00**	0.06	1.87	(0.06)	0.39	(0.04)	(0.25)	(4.46)
Per common share - diluted	**0.98**	0.06	1.85	(0.06)	0.39	(0.04)	(0.25)	(4.46)
Adjusted funds flow (1)	**214,766**	198,397	175,883	156,582	82,176	78,508	17,887	132,935
Per common share - basic	**0.38**	0.35	0.31	0.28	0.15	0.14	0.03	0.24
Per common share - diluted	**0.37**	0.35	0.31	0.28	0.15	0.14	0.03	0.24
Free cash flow (2)	**137,133**	101,215	112,486	70,495	1,794	59,939	5,939	(49,599)
Per common share - basic	**0.24**	0.18	0.20	0.13	—	0.11	0.01	(0.09)
Per common share - diluted	**0.24**	0.18	0.20	0.13	—	0.11	0.01	(0.09)
Cash flows from operating activities	**240,567**	178,961	171,876	120,980	51,017	93,688	25,824	182,567
Per common share - basic	**0.43**	0.32	0.30	0.22	0.09	0.17	0.05	0.33
Per common share - diluted	**0.42**	0.31	0.30	0.22	0.09	0.17	0.05	0.33
Exploration and development	**73,995**	94,235	61,485	83,588	77,809	15,902	9,852	176,777
Canada	**59,821**	75,499	30,387	42,503	45,030	3,882	2,929	123,110
U.S.	**14,174**	18,736	31,098	41,085	32,779	12,020	6,923	53,667
Property acquisitions	**1,443**	89	—	25	—	—	—	—
Proceeds from dispositions	**(6,857)**	(701)	(18)	(228)	(33)	(98)	(11)	(40)
Net debt (1)	**1,409,717**	1,564,658	1,629,629	1,758,894	1,847,601	1,906,079	1,994,953	2,051,617
Total assets	**4,834,643**	4,453,971	4,438,162	3,338,408	3,408,096	3,156,414	3,267,820	3,441,040
Common shares outstanding	**564,213**	564,213	564,182	564,111	561,227	561,163	560,545	560,483
Daily production								
Total production (boe/d)	**80,789**	79,872	81,162	78,780	70,475	77,814	72,508	98,452
Canada (boe/d)	**50,362**	48,124	47,205	52,039	45,321	49,164	37,691	62,262
U.S. (boe/d)	**30,428**	31,748	33,957	26,741	25,154	28,650	34,817	36,190
Benchmark prices								
WTI oil (US$/bbl)	**77.19**	70.56	66.07	57.84	42.66	40.93	27.85	46.17
WCS heavy ($/bbl)	**78.82**	71.81	67.03	57.46	43.46	42.40	22.70	34.48
Edmonton Light ($/bbl)	**93.29**	83.78	77.28	66.58	50.24	49.83	29.85	51.43
CAD/USD avg exchange rate	**1.2600**	1.2601	1.2279	1.2663	1.3031	1.3316	1.3860	1.3445
AECO gas ($/mcf)	**4.94**	3.54	2.85	2.93	2.77	2.18	1.91	2.14
NYMEX gas (US$/mmbtu)	**5.83**	4.01	2.83	2.69	2.66	1.98	1.72	1.95
Total sales, net of blending and other expense ($/boe) (2)	**70.42**	63.85	57.19	51.84	34.35	33.79	22.31	35.19
Royalties ($/boe) (3)	**(13.47)**	(12.32)	(11.04)	(9.44)	(5.83)	(5.59)	(4.42)	(6.33)
Operating expense ($/boe) (3)	**(12.83)**	(11.46)	(11.22)	(11.36)	(12.30)	(10.26)	(11.17)	(11.66)
Transportation expense ($/boe) (3)	**(1.10)**	(1.06)	(1.01)	(1.24)	(1.03)	(0.89)	(0.76)	(1.15)
Operating netback ($/boe) (2)	**43.02**	39.01	33.92	29.80	15.19	17.05	5.96	16.05
Financial derivatives gain (loss) ($/boe) (3)	**(9.49)**	(7.34)	(5.28)	(2.93)	2.64	(1.36)	2.06	3.00
Operating netback after financial derivatives ($/boe) (2)	**33.53**	31.67	28.64	26.87	17.83	15.69	8.02	19.05

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

(3) *Calculated as Operating, transportation or financial derivatives gain (loss) expense divided by barrels of oil equivalent production volume for the applicable period.*

Our results for the previous eight quarters reflect the disciplined execution of our development programs and management of production in response to fluctuations in the prices for the commodities we produce. Production declined from Q1/2020 to Q2/2020 due to the sharp decline in crude oil prices in March 2020 when we shut-in production in Canada and moderated the pace of activity in the U.S. Commodity prices began to recover in Q3/2020 and have strengthened throughout 2021 which supported increased development activity and resulted in production of 80,789 boe/d for Q4/2021.

North American benchmark commodity prices were relatively strong leading in to Q1/2020 with the West Texas Intermediate ("WTI") benchmark price averaging US$57.53/bbl in January 2020. Decisions made by Saudi Arabia and Russia to increase production of crude oil as demand was decreasing due to the spread of COVID-19 resulted in a sharp decline in global crude oil prices with WTI averaging US$27.85/bbl in Q2/2020. Prices improved during the second half of 2020 as OPEC+ agreed to reinstate production curtailments and measures to control the spread of COVID-19 were relaxed. Commodity prices continued to strengthen in 2021 with WTI hitting multi-year highs and averaging US$77.19/bbl in Q4/2021 as the outlook for demand improved with increasing global mobility and supply growth was limited by OPEC+ production curtailments along with limited production growth from large independent producers. The impact of increased commodity prices is reflected in our realized sales price of $70.42/boe for Q4/2021 which is our strongest realized price for the previous eight quarters.

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(1) improved throughout 2021, to $214.8 million in Q4/2021, due to strong price realizations and ongoing efforts to control operating and transportation costs.

Net debt can fluctuate depending on the timing of exploration and development expenditures, changes in our adjusted funds flow and the closing CAD/USD exchange rate which is used to translate our U.S. dollar denominated debt. Net debt(1) has decreased from $2.1 billion at Q1/2020 to $1.4 billion at Q4/2021 as free cash flow(2) of $439.4 million generated over the last eight quarters has been directed towards debt repayment. Our net debt has also been reduced by a decrease in the CAD/USD exchange rate used to translate our U.S. dollar denominated debt from 1.412 CAD/USD at Q1/2020 to 1.2656 CAD/USD at Q4/2021.

(1) *Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.*
(2) *Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.*

ENVIRONMENTAL REGULATIONS

As a result of our involvement in the exploration and production of oil and natural gas we are subject to various emissions, carbon and other environmental regulations. Refer to the Risk Factors section of this MD&A for a full description of the risks associated with these regulations and how they may impact our business in the future. In addition to the Risk Factors discussed in this MD&A, additional information related to our emissions and sustainability initiatives is available on our website.

Reporting Regulations

Environmental reporting for public enterprises continues to evolve and we may be subject to additional future disclosure requirements. The International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the objective to develop a global framework for environmental sustainability disclosure. The Canadian Securities Administrators have also issued a proposed National Instrument 51-107 *Disclosure of Climate-related Matters* which sets forth additional reporting requirements for Canadian Public Companies. We continue to monitor developments on these reporting requirements and have not yet quantified the cost to comply with these regulations.

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at December 31, 2021, 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, including considerations related to environmental regulation and related matters, 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, evaluating the recoverability of deferred income tax assets 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.

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

Tax regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and there are differing interpretations requiring management judgment. Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in future periods, which requires management judgment. Deferred tax liabilities are recognized when it is considered probable that temporary differences will be payable to tax authorities in future periods, which 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.

NYSE LISTING

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

Baytex's common shares remain registered with the U.S. Securities and Exchange Commission. Given that Baytex remains listed on the TSX and the average daily trading volume of Baytex’s common shares in the U.S. is greater than 5% of Baytex’s worldwide average daily trading volume over the 12-month period following the delisting, Baytex is not eligible to deregister its common shares and must continue to follow the reporting guidelines of the Securities Exchange Act of 1934, as amended.

SPECIFIED FINANCIAL MEASURES

In this MD&A, we refer to certain specified financial measures (such as free cash flow, operating netback, total sales, net of blending and other expense, heavy oil sales, net of blending and other expense, and average royalty rate) which do not have any standardized meaning prescribed by IFRS. While these measures 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. This MD&A also contains the terms "adjusted funds flow", "net debt" and "net debt to adjusted funds flow ratio" which are capital management measures. We believe that inclusion of these specified financial measures provides useful information to financial statement users when evaluating the financial results of Baytex.

Non-GAAP Financial Measures

Total sales, net of blending and other expense

Total sales, net of blending and other expense represents the revenues realized from produced volumes during a period. Total sales, net of blending and other expense is comprised of total petroleum and natural gas sales adjusted for blending and other expense. We believe including the blending and other expense associated with purchased volumes is useful when analyzing our realized pricing for produced volumes against benchmark commodity prices.

Operating netback

Operating netback and operating netback after financial derivatives are used to assess our operating performance and our ability to generate cash margin on a unit of production basis. Operating netback is comprised of petroleum and natural gas sales, less blending expense, royalties, operating expense and transportation expense. Realized financial derivatives gains and losses are added to operating netback to provide a more complete picture of our financial performance as our financial derivatives are used to provide price certainty on a portion of our production.

The following table reconciles operating netback and operating netback after realized financial derivatives to petroleum and natural gas sales.

	Years Ended December 31	
($ thousands)	**2021**	2020
Petroleum and natural gas sales	**$ 1,868,195**	$ 975,477
Blending and other expense	**(85,689)**	(48,381)
Total sales, net of blending and other expense	**1,782,506**	927,096
Royalties	**(339,156)**	(163,735)
Operating expense	**(343,002)**	(331,345)
Transportation expense	**(32,261)**	(28,437)
Operating netback	**1,068,087**	403,579
Realized financial derivatives (gain) loss(1)	**(184,241)**	47,836
Operating netback after realized financial derivatives	**$ 883,846**	$ 451,415

(1) Realized financial derivatives gain or loss is a component of financial derivatives gain or loss; see Note 17 Financial Instruments and Risk Management in the Consolidated Financial Statements for the year ended December 31, 2021 for further information.

Free cash flow

We use free cash flow to evaluate our financial performance and to assess the cash available for debt repayment, common share repurchases, dividends and acquisition opportunities. Free cash flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital, additions to exploration and evaluation assets, additions to oil and gas properties and payments on lease obligations.

Free cash flow is reconciled to cash flows from operating activities in the following table.

	Years Ended December 31	
($ thousands)	**2021**	2020
Cash flows from operating activities	**$ 712,384**	$ 353,096
Change in non-cash working capital	**26,582**	$ (48,758)
Additions to exploration and evaluation assets	**(3,298)**	(4,490)
Additions to oil and gas properties	**(310,005)**	(275,850)
Payments on lease obligations	**(4,334)**	(5,925)
Free cash flow	**$ 421,329**	$ 18,073

Non-GAAP Financial Ratios

Heavy oil, net of blending and other expense per bbl

Heavy oil, net of blending and other expense per bbl represents the realized price for produced heavy oil volumes during a period. Heavy oil, net of blending and other expense is a non-GAAP financial ratio that is divided by barrels of heavy oil production volume for the applicable period to calculate the ratio. We use heavy oil, net of blending and other expense per bbl to analyze our realized heavy oil price for produced volumes against the WCS benchmark price.

Total sales, net of blending and other expense per boe

Total sales, net of blending and other per boe is used to compare our realized pricing to applicable benchmark prices and is calculated as total sales, net of blending and other expense (a non-GAAP financial measure) divided by barrels of oil equivalent production volume for the applicable period.

Average royalty rate

Average royalty rate is used to evaluate the performance of our operations from period to period and is comprised of royalties divided by total sales, net of blending and other expense (a non-GAAP financial measure). 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.

Operating netback per boe

Operating netback per boe is operating netback (a non-GAAP financial measure) divided by barrels of oil equivalent production volume for the applicable period and is used to assess our operating performance on a unit of production basis. Realized financial derivative gains and losses per boe are added to operating netback per boe to arrive at operating netback after financial derivatives per boe. Realized financial derivatives gains and losses are added to operating netback to provide a more complete picture of our financial performance as our financial derivatives are used to provide price certainty on a portion of our production.

Capital Management Measures

Net debt

We use net debt to monitor our current financial position and to evaluate existing sources of liquidity. We also use net debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations. Net debt is comprised our credit facilities and long-term notes outstanding adjusted for unamortized debt issuance costs, trade and other payables, cash, and trade and other receivables.

The following table summarizes our calculation of net debt.

($ thousands)		**December 31, 2021**		December 31, 2020
Credit facilities	**$**	**505,171**	$	649,221
Unamortized debt issuance costs - Credit facilities(1)		**1,343**		1,952
Long-term notes		**874,527**		1,132,868
Unamortized debt issuance costs - Long-term notes(1)		**11,393**		15,082
Trade and other payables		**190,692**		155,955
Trade and other receivables		**(173,409)**		(107,477)
Net debt	**$**	**1,409,717**	$	1,847,601

(1) Unamortized debt issuance costs were obtained from Note 7 Credit Facilities and Note 8 Long-term Notes from the Consolidated Financial Statements for the year ended December 31, 2021. These amounts represent the remaining balance of costs that were paid by Baytex at the inception of the contract.

Adjusted funds flow

Adjusted funds flow is used to monitor operating performance and the our ability to generate funds for exploration and development expenditures and settlement of abandonment obligations. Adjusted funds flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital and asset retirements obligations settled during the applicable period. We also use a net debt to adjusted funds flow ratio calculated on a twelve-month trailing basis to monitor our existing capital structure and future liquidity requirements. Net debt to adjusted funds flow is comprised of net debt divided by adjusted funds flow.

Adjusted funds flow is reconciled to amounts disclosed in the primary financial statements in the following table.

	Years Ended December 31			
($ thousands)		**2021**		2020
Cash flows from operating activities	**$**	**712,384**	$	353,096
Change in non-cash working capital		**26,582**		(48,758)
Asset retirement obligations settled		**6,662**		7,168
Adjusted funds flow	**$**	**745,628**	$	311,506
Net debt to adjusted funds flow		**1.9**		5.9

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As of December 31, 2021, an evaluation was conducted to determine 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, 2021.

The effectiveness of our internal control over financial reporting as of December 31, 2021 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, 2021 that have materially affected, or are reasonably likely to materially affect, the internal controls over financial reporting.

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)		**2021**		2020		2019
Revenues, net of royalties	**$**	**1,529,039**	$	811,742	$	1,485,678
Adjusted funds flow [(1)]	**$**	**745,628**	$	311,506	$	902,426
Per common share - basic	**$**	**1.32**	$	0.56	$	1.62
Per common share - diluted	**$**	**1.30**	$	0.56	$	1.62
Net income (loss)	**$**	**1,613,600**	$	(2,438,964)	$	(12,459)
Per common share - basic	**$**	**2.86**	$	(4.35)	$	(0.02)
Per common share - diluted	**$**	**2.82**	$	(4.35)	$	(0.02)
Total assets	**$**	**4,834,643**	$	3,408,096	$	5,914,083
Credit facilities - principal	**$**	**506,514**	$	651,173	$	506,471
Long term notes - principal	**$**	**885,920**	$	1,147,950	$	1,337,200
Total sales, net of blending and other expense ($/boe) [(2)]	**$**	**60.93**	$	31.75	$	48.72
Total production (boe/d)		**80,156**		79,781		97,680

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

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; for 2022, our capital budget, expected average daily production, expected royalty rate and operating expense, transportation expense, general and administrative expense, cash interest expense, lease expenditures and asset retirement obligations settled; the existence, operation and strategy of our risk management program; the reassessment of our tax filings by the Canada Revenue Agency; 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 or repurchase 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; our plans with respect to asset retirement obligation activities; and the circumstances in which we may be eligible to deregister our common shares under the Securities Exchange Act of 1934. 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: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices and price differentials (including the impacts of Covid-19); restrictions or costs imposed by climate change initiatives and the physical risks of climate change; risks associated with our ability to develop our properties and add reserves; the impact of an energy transition on demand for petroleum productions; changes in income tax or other laws or government incentive programs; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; the availability and cost of capital or borrowing; risks associated with a third-party operating our Eagle Ford properties; risks associated with large projects; costs to develop and operate our properties; public perception and its influence on the regulatory regime; current or future control, legislation or regulations; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; regulations regarding the disposal of fluids; risks associated with our hedging activities; variations in interest rates and foreign exchange rates; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; additional risks associated with our thermal heavy oil projects; our ability to compete with other organizations in the oil and gas industry; risks associated with our use of information technology systems; results of litigation; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks of counterparty default; the impact of Indigenous claims; risks associated with expansion into new activities; 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, 2021, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission not later than March 31, 2022 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.

Risks Relating to Our Business and Operations

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, OPEC+, the condition of the Canadian, United States, European and Asian economies, the impact of pandemics/epidemics (including Covid-19), 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 change, the carrying value of our assets could be subject to revision and our net earnings could be adversely affected.

Restrictions and/or costs associated with regulatory initiatives to combat climate change and the physical risks of climate change may have a material adverse affect on our business

Regulatory and Policy Initiatives

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. In addition, certain of our assets have a higher GHG emissions intensity than others and may be disproportionately impacted.

Negative consequences which could result from new GHG emissions regulation include, but are not limited to: increased operating costs, additional taxes, 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 our financial condition, results of operations or prospects.

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.

Physical Risk

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rain fall, hurricanes and wildfires may restrict our ability to access our properties, cause operational difficulties including damage to machinery and facilities. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of our assets are located where they are exposed to forest fires, floods, heavy rains, hurricanes and other extreme weather conditions which can lead to significant downtime, damage to such assets and/or increased costs of construction and maintenance. Moreover, extreme weather conditions may lead to disruptions in our ability to transport produced oil and natural gas as well as goods and services in our supply chain.

Our success is highly dependent on our ability to develop existing properties and add to our oil and natural gas reserves

Our oil and natural gas reserves are a depleting resource and decline as such reserves are produced, as a result, 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 hydrocarbons 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.

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 our business, financial condition, results of operations and prospects.

An energy transition that lessens demand for petroleum products may have an adverse affect on our business

A transition away from the use of petroleum products, which may include 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. We cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on our business and financial condition by decreasing our cash flow from operating activities and the value of our assets.

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

Income tax laws and government incentive programs relating to the oil and gas industry may change in a manner that adversely affects our financial condition, results of operations and prospects.

In addition, 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. 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.

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. In addition, many of the pipeline systems that we use are controlled by a single company and rates are set through a regulatory process, as a result we are subject to the outcome of those regulatory processes. Any significant change in market factors, regulatory decisions 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.

Access to the pipeline capacity for the export of crude oil from Canada has, at times, been inadequate for the amount of Canadian production being exported. This has resulted in significantly lower prices being realized by Canadian producers compared with the WTI price and the Brent price for crude oil. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas from Canada. There can be no certainty that current investment in pipelines will provide sufficient long-term take-away capacity or that currently operating systems will remain in service. 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 retain or replace our leadership and key personnel may have an adverse affect on our business

Our success is dependent upon our management, our leadership capabilities and the quality and competency of our talent. If we are unable to retain key personnel and critical talent or to attract and retain new talent with the necessary leadership, professional and technical competencies, it could have a material adverse effect on our financial condition, results of operations and prospects.

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

The business of exploring for, developing or acquiring reserves is capital intensive. If external sources of capital (including, but not limited to, debt and equity financing) 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. 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 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.

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. Additionally, from time to time, our securities may not meet the investment criteria or characteristics of a particular institutional or other investor, including institutional investors who are not willing or able to hold securities of oil and gas companies for reasons unrelated to financial or operational performance. This may include changes to market-based factors or investor strategies, including ESG, or responsible investing criteria/rankings (for example, ESG, social impact or environmental scores), the implementation of new financial market regulations and fossil fuel divestment initiatives undertaken by governments, pension funds and/or other institutional investors. These events 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 or equity. 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. Additionally, from time to time, we may issue securities from treasury in order to reduce debt, complete acquisitions and/or optimize our capital structure.

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 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.

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.

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, community relationships 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 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, access to skilled and unskilled labour, availability of equipment, scheduling delays, trucking and fuel costs, failure to maintain quality construction standards, the cost of new technologies and supply chain disruptions. Labour costs, natural gas, electricity, water, diluent and chemicals are examples of some of the operating and other costs that are susceptible to significant fluctuation. Increases to development and operating costs could have a material adverse effect on our financial condition, results of operations or prospects.

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.

Current or future controls, legislation or regulations applicable to the oil and gas industry could adversely affect us

Operations

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. 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. The exercise of discretion by government 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 could have a material adverse effect on our financial condition, results of operations or prospects.

Environment

All phases of our operations are subject to environmental and health and safety regulation pursuant to a variety of federal, provincial, state and municipal laws and regulations (collectively, "**environmental regulations**") governing occupational health and safety, the spill, release or emission of substances 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 require the submission and approval of environmental impact assessments or permit applications. Environmental regulations impose 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. The jurisdictions where we operate 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. 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 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 could reduce demand for crude oil and natural gas, result 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.

Foreign Investment and Competition Act Legislation

In addition to regulatory requirements 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 the *Hart-Scott-Rodino Antitrust Improvements Act* in the United States.

New regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes

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 our 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.

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

We undertake or intend to undertake certain hydraulic fracturing, SAGD, CCS and waterflooding programs. To undertake such operations we need to have access to sufficient volumes of water, or other liquids. There is no certainty that we 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, SAGD, CCS and waterflooding. If we are unable to access such water it may not be able to undertake hydraulic fracturing, SAGD, CCS or waterflooding activities, which may reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Regulations regarding the disposal of fluids used in our operations may increase our 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, provincial and state 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 our costs of compliance.

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 for certain assets will 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.

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 prospects.

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.

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

The reserves estimates included in the AIF are estimates only. 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, 2021 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 physical 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, theft 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.

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.

We may be unable to compete successfully with other organizations in the oil and natural gas industry, or obtain required vendor services to compete

The oil and natural gas industry is highly competitive. We compete for capital, acquisitions of reserves and/or resources, undeveloped lands, skilled/qualified labour, access to drilling rigs, service rigs and other equipment and materials such as drilling rigs, hydraulic fracturing pumping equipment and related skilled personnel, access to processing facilities, pipeline and refining capacity, as well as many other services, and in many other respects, with a substantial number of other organizations, many of which may have greater technical and financial resources than us. As a result, some of our competitors may have greater opportunities and be able to access, services or vendors that we are not able to access, thereby limiting our ability to compete.

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 and are subject to a variety of information technology and system risks as a part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Corporation's information technology systems by third parties or insiders. 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 the Corporation has security measures and controls in place to mitigate these risks, a breach of its security measures and/or a loss of information could occur and result in a loss of material and confidential information and reputation, breach of privacy laws, and/or disruption to business activities. The significance of any such event is difficult to quantify but may in certain circumstances be material and could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Adverse results from litigation may have an adverse affect on our business

In the normal course of our operations, we may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions. Potential litigation may develop in relation to personal injuries, property damage, royalties, taxes, land and access rights, environmental issues, natural resource damages and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to us and could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations. Even if we prevail in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse affect on our financial condition.

Our Credit Facilities may not provide sufficient liquidity and a failure to renew our Credit Facilities at maturity 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, 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.

Failure to comply with the covenants in the agreements governing our debt, including our obligation to repay the Senior Notes at maturity, could adversely affect our financial condition

We are required to comply with the covenants in our Credit Facilities and the Senior Notes. If we fail to comply with such covenants, are unable to repay or refinance amounts owned at maturity or 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 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.

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.

Indigenous Claims

Indigenous peoples have claimed Indigenous rights and title in portions of Western Canada. We are not aware that any claims have been made in respect of our properties and assets. However, if a claim arose and was successful, such claim may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays in the construction of infrastructure systems and facilities which could have a material adverse effect on our business and financial results.

Expansion into New Activities

Our operations and the expertise of our management are currently focused primarily on oil and natural gas production, exploration and development in the Provinces of Alberta and Saskatchewan and the State of Texas. In the future, we may acquire or move into new industry related activities or new geographical areas and may acquire different energy-related assets; as a result, we may face unexpected risks or, alternatively, our exposure to one or more existing risk factors may be significantly increased, which may in turn result in our future operational and financial conditions being adversely affected.

Risks Related to Ownership of our Securities

Changes in market-based factors may adversely affect the trading price of the Common Shares

The market price of our Common Shares is sensitive to a variety of market-based factors including, but not limited to, commodity prices, interest rates, foreign exchange rates, the decision of certain indices to include our Common Shares and the comparability of the Common Shares to other securities. Any changes in these market-based factors may adversely affect the trading price of the Common Shares.

Forward-Looking Information rely upon assumptions which may not prove correct

Shareholders and prospective investors are cautioned not to place undue reliance on our forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Certain Risks for United States and other non-resident Shareholders

The ability of investors resident in the United States to enforce civil remedies is limited

We are a corporation incorporated under the laws of the Province of Alberta, Canada, our principal office is located in Calgary, Alberta and a substantial portion of our assets are located outside the United States. Most of our directors and officers and the representatives of the experts who provide services to us (such as our auditors and our independent qualified reserves evaluators), and all or a substantial portion of their assets are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgments of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against us or any of our directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

Canadian and United States practices differ in reporting reserves and production and our estimates may not be comparable to those of companies in the United States

We report our production and reserves quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the SEC by companies in the United States.

We incorporate additional information with respect to production and reserves which is either not required to be included or prohibited under rules of the SEC and practices in the United States. We follow the Canadian practice of reporting gross production and reserve volumes (before deduction of Crown and other royalties). We also follow the Canadian practice of using forecast prices and costs when we estimate our reserves, whereas the SEC rules require that a 12-month average price, calculated as the unweighted 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, be utilized.

Probable reserves have a lower certainty of recovery than proved reserves. 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. The SEC definitions of proved reserves and probable reserves are different than NI 51-101; therefore, our disclosure of proved, probable and proved plus probable reserves may not be comparable to United States standards.

As a consequence of the foregoing, our reserves estimates and production volumes may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

There is additional taxation applicable to non-residents

Tax legislation in Canada may impose withholding or other taxes on the cash dividends, stock dividends or other property transferred by us to non-resident shareholders. These taxes may be reduced pursuant to tax treaties between Canada and the non-resident shareholder's jurisdiction of residence. Evidence of eligibility for a reduced withholding rate must be filed by the non-resident shareholder in prescribed form with their broker (or in the case of registered shareholders, with the transfer agent). In addition, the country in which the non-resident shareholder is resident may impose additional taxes on such dividends. Any of these taxes may change from time to time.