Q1 REPORT

2022

TSX BTE

BAYTEX ANNOUNCES FIRST QUARTER 2022 RESULTS, STRONG PEAVINE DRILLING, INCREASED GUIDANCE AND PLANNED SHARE BUYBACK PROGRAM

CALGARY, ALBERTA (April 28, 2022) - Baytex Energy Corp. ("Baytex")(TSX: BTE) reports its operating and financial results for the three months ended March 31, 2022 (all amounts are in Canadian dollars unless otherwise noted).

“We remain focused on capital discipline, generating free cash flow and reducing debt. We also materially advanced our Clearwater development with ten wells drilled at Peavine, including three wells averaging 30-day initial production rates of 1,100 bbl/d per well. These exceptional wells have enabled us to more than double our Clearwater production to 8,000 bbl/d today. As a result, we are pleased to increase our 2022 production guidance and add six new Clearwater wells to our Q4/2022 program. Our focus on delivering substantial free cash flow is unchanged - our updated five-year plan (2022 through 2026) is expected to generate approximately $3 billion of cumulative free cash flow. I am also excited to announce that our board of directors has approved a share buyback program that is expected to commence in May," commented Ed LaFehr, President and Chief Executive Officer.

Q1 2022 Highlights

- Generated production of 80,867 boe/d (82% oil and NGL) in Q1/2022, a 3% increase over Q1/2021.
- Delivered adjusted funds flow[(1)] of $280 million ($0.49 per basic share) in Q1/2022, a 78% increase compared to $157 million ($0.28 per basic share) in Q1/2021.
- Generated free cash flow[(2)] of $121 million ($0.21 per basic share) in Q1/2022, a 72% increase compared to $70 million ($0.13 per basic share) in Q1/2021.
- Cash flows from operating activities was $199 million ($0.35 per basic share) in Q1/2022, a 64% increase compared to $121 million ($0.22 per basic share) in Q1/2021.
- Reduced net debt[(1)] by 10% to $1.28 billion, from $1.41 billion at year-end 2021.
- Drilled 10 Clearwater wells at Peavine in Q1/2022 with our first three wells generating an average 30-day initial production rate of 1,100 bbl/d per well, boosting field production to 8,000 bbl/d today.
- Increasing exploration and development expenditures and production guidance given strong Peavine results and inflationary pressure.
- We intend to repurchase and cancel the remaining US$200 million principal amount of 5.625% long-term notes at par on June 1, 2022.

2022 Outlook

We remain intensely focused on maintaining capital discipline and driving meaningful free cash flow in our business. Based on the forward strip[(3)], we expect to generate approximately $700 million ($1.25 per basic share) of free cash flow this year. As part of our previously announced return of capital framework, we expect to allocate approximately 25% of our annual free cash flow to direct shareholder returns through a share buyback program commencing in May of 2022.

The remainder of our free cash flow will continue to be allocated to debt reduction until we achieve a net debt level of $800 million, which represents an expected net debt[(1)] to EBITDA[(4)] ratio of 1.0x at a US$55 WTI price. This level of net debt will provide us with flexibility to run our business through the commodity price cycles and generate meaningful returns for our shareholders. At current prices, we expect to achieve this net debt level in early 2023, at which point we will consider steps to further enhance shareholder returns.

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release 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 press release for further information.
(3) 2022 full-year pricing assumptions: WTI - US$94/bbl; WCS differential - US$13/bbl; MSW differential – US$2/bbl, NYMEX Gas - US$5.60/mcf; AECO Gas - $5.30/mcf and Exchange Rate (CAD/USD) - 1.26.
(4) Calculated in accordance with the Credit Facilities Agreement.

Our operational success, the continued strong economics of our drilling program and the inflationary pressures being experienced throughout our industry caused us to review our capital program for the year. We are now forecasting 2022 exploration and development expenditures of $450 to $500 million, up from $400 to $450 million, which was set in a US$65 pricing environment. The incremental capital reflects additional activity on our Clearwater lands and the Eagle Ford as well as expected capital cost inflation.

With continued strong operating momentum and production growth on our Clearwater lands, we are increasing our production guidance for 2022 to 83,000 to 85,000 boe/d, up from 80,000 to 83,000 boe/d, previously, and expect to exit 2022 producing approximately 87,000 to 88,000 boe/d.

The Clearwater has emerged as one of the most profitable plays in North America and our Q1/2022 drilling program has delivered exceptional results. As a result, we are expanding our 2022 plan to run a full one rig program at Peavine through year-end (previously budgeted plans had our drilling program wrapping up in September) which results in an incremental six wells being drilled in Q4/2022. We also anticipate drilling 2-3 net incremental wells in the Eagle Ford in H2/2022, the highest free cash flow generating asset in our portfolio. This increased activity set will result in $30 million of incremental exploration and development expenditures, which is offset by approximately $10 million of reduced light oil activity.

We have also updated our 2022 plan to reflect an incremental 8% expected capital cost inflation, which increases our exploration and development expenditures by approximately $30 million. This reflects industry cost pressures related to labour, logistics, fuel and tangible items such as steel, frac sand and chemicals. In aggregate, we are now assuming 18% capital cost inflation in 2022, as compared to 2021.

We have fine-tuned several of our cost assumptions to reflect increased royalties due to higher commodity prices and inflationary pressures on operating and transportation expenses related to labor, fuel, electricity and hauling. Offsetting these cost pressures to a certain extent is increased production and a reduction in our interest expense as our net debt is reduced.

The following table highlights our updated 2022 annual guidance.

	2022 Guidance (1)	**2022 Revised Guidance**
Exploration and development expenditures	$400 - $450 million	$450 - $500 million
Production (boe/d)	80,000 - 83,000	83,000 - 85,000
Expenses:		
Average royalty rate (2)	18.5% - 19.0%	20.0% - 20.5%
Operating (3)	$12.25 - $13.00/boe	$13.00 - $13.50/boe
Transportation (3)	$1.20 - $1.30/boe	$1.30 - $1.40/boe
General and administrative (3)	$43 million ($1.45/boe)	$43 million ($1.40/boe)
Interest (3)	$80 million ($2.70/boe)	$75 million ($2.45/boe)
Leasing expenditures	$3 million	no change
Asset retirement obligations	$20 million	no change

Notes:

(1) As announced on December 1, 2021.
(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 press release for further information.
(3) Calculated as operating, transportation, general and administrative or interest expense divided by barrels of oil equivalent production volume for the applicable period.

Update to Five-Year Plan

We introduced our five-year plan one year ago (April 2021) to highlight our financial and operational sustainability and ability to generate meaningful free cash flow. We continue to benchmark our results to this five-year plan and intend to update as warranted based on the macro-environment (commodity prices, cost inflation) and drilling results and activity across our land base.

We are now rolling our five-year plan forward to capture the period 2022 to 2026. Year one of the five-year plan is based on 2022 guidance and forward strip commodity prices and years two through five (2023 through 2026) are based on a constant US$75 WTI price. Our focus on delivering free cash flow is unchanged - under these pricing assumptions, we expect to generate approximately $3 billion of cumulative free cash flow(1) during the plan period.

We have also updated our five-year plan to include expected inflationary cost increases along with increased drilling on our Clearwater lands that has us drilling approximately 120 net wells through 2026. With this updated view of our land base, we expect Clearwater production to increase from zero at the beginning of 2021 to approximately 10,000 bbl/d while generating over $400 million of cumulative free cash flow. With continued success, we believe the play ultimately holds the potential for over 200 drilling locations that could support production increasing to over 15,000 bbl/d.

Through this plan period, we are committed to a disciplined, returns based capital allocation philosophy, targeting exploration and development expenditures at less than 50% of our adjusted funds flow. We expect to generate annual production growth of 2% to 4%, with production reaching approximately 95,000 boe/d in 2026.

Normal Course Issuer Bid

Given the strength of our balance sheet and consistent with our desire to offer direct shareholder returns, the Board of Directors has approved the filing of a Normal Course Issuer Bid ("NCIB") application with the TSX for a share buyback program of up to 56 million common shares, representing approximately 10% of our public float.

(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 press release for further information.

	Three Months Ended		
	March 31, 2022	December 31, 2021	March 31, 2021
FINANCIAL (thousands of Canadian dollars, except per common share amounts)			
Petroleum and natural gas sales	**$ 673,825**	$ 552,403	$ 384,702
Adjusted funds flow (1)	**279,607**	214,766	156,582
Per share - basic	**0.49**	0.38	0.28
Per share - diluted	**0.49**	0.37	0.28
Free cash flow (2)	**121,318**	137,133	70,495
Per share – basic	**0.21**	0.24	0.13
Per share – diluted	**0.21**	0.24	0.13
Cash flows from operating activities	**198,974**	240,567	120,980
Per share – basic	**0.35**	0.43	0.22
Per share – diluted	**0.35**	0.42	0.22
Net income (loss)	**56,858**	563,239	(35,352)
Per share - basic	**0.10**	1.00	(0.06)
Per share - diluted	**0.10**	0.98	(0.06)
Capital Expenditures			
Exploration and development expenditures	**$ 153,822**	$ 73,995	$ 83,588
Acquisitions and divestitures	**32**	(5,414)	(203)
Total oil and natural gas capital expenditures	**$ 153,854**	$ 68,581	$ 83,385
Net Debt			
Credit facilities	**$ 426,858**	$ 506,514	$ 606,637
Long-term notes	**873,880**	885,920	1,131,480
Long-term debt	**1,300,738**	1,392,434	1,738,117
Working capital	**(25,058)**	17,283	20,777
Net debt (1)	**$ 1,275,680**	$ 1,409,717	$ 1,758,894
Shares Outstanding - basic (thousands)			
Weighted average	**565,518**	564,213	562,085
End of period	**569,214**	564,213	564,111
BENCHMARK PRICES			
Crude oil			
WTI (US$/bbl)	**$ 94.29**	$ 77.19	$ 57.84
MEH oil (US$/bbl)	**96.72**	78.89	59.36
MEH oil differential to WTI (US$/bbl)	**2.43**	1.70	1.52
Edmonton par ($/bbl)	**115.66**	93.29	66.58
Edmonton par differential to WTI (US$/bbl)	**(2.94)**	(3.15)	(5.27)
WCS heavy oil ($/bbl)	**100.99**	78.82	57.46
WCS differential to WTI (US$/bbl)	**(14.53)**	(14.63)	(12.46)
Natural gas			
NYMEX (US$/mmbtu)	**$ 4.95**	$ 5.83	$ 2.69
AECO ($/mcf)	**4.59**	4.94	2.93
CAD/USD average exchange rate	**1.2661**	1.2600	1.2663

	Three Months Ended		
	March 31, 2022	December 31, 2021	March 31, 2021
OPERATING			
Daily Production			
Light oil and condensate (bbl/d)	**34,065**	34,986	35,430
Heavy oil (bbl/d)	**25,236**	23,482	21,989
NGL (bbl/d)	**7,636**	7,984	6,238
Total liquids (bbl/d)	**66,937**	66,452	63,657
Natural gas (mcf/d)	**83,574**	86,029	90,739
Oil equivalent (boe/d @ 6:1) [3]	**80,867**	80,789	78,780
Netback (thousands of Canadian dollars)			
Total sales, net of blending and other expense [2]	**$ 632,385**	$ 523,382	$ 367,582
Royalties	**(122,720)**	(100,152)	(66,950)
Operating expense	**(100,766)**	(95,357)	(80,548)
Transportation expense	**(9,215)**	(8,169)	(8,788)
Operating netback [2]	**$ 399,684**	**$ 319,704**	**$ 211,296**
General and administrative	**(11,682)**	(11,481)	(8,733)
Cash financing and interest	**(20,427)**	(21,319)	(24,403)
Realized financial derivatives loss	**(84,366)**	(70,544)	(20,768)
Other [4]	**(3,602)**	(1,594)	(810)
Adjusted funds flow [1]	**$ 279,607**	**$ 214,766**	**$ 156,582**
Netback (per boe) [5]			
Total sales, net of blending and other expense [2]	**$ 86.89**	$ 70.42	$ 51.84
Royalties	**(16.86)**	(13.47)	(9.44)
Operating expense	**(13.85)**	(12.83)	(11.36)
Transportation expense	**(1.27)**	(1.10)	(1.24)
Operating netback [2]	**$ 54.91**	**$ 43.02**	**$ 29.80**
General and administrative	**(1.61)**	(1.54)	(1.23)
Cash financing and interest	**(2.81)**	(2.87)	(3.44)
Realized financial derivatives loss	**(11.59)**	(9.49)	(2.93)
Other [4]	**(0.48)**	(0.23)	(0.12)
Adjusted funds flow [1]	**$ 38.42**	**$ 28.89**	**$ 22.08**

Notes:

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release 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 press release for further information.
(3) Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. The use of boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
(4) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and cash share-based compensation. Refer to the Q1/2022 MD&A for further information on these amounts.
(5) Calculated as royalties, operating, transportation, general and administrative, cash financing and interest or realized financial derivatives loss expense divided by barrels of oil equivalent production volume for the applicable period.

Q1/2022 Results

In Q1/2022, we delivered strong operating and financial results and continued to advance our exciting new Clearwater play in northwest Alberta.

Production during the first quarter averaged 80,867 boe/d (82% oil and NGL) as compared to 80,789 boe/d (82% oil and NGL) in Q4/2021. Exploration and development expenditures totaled $154 million in Q1/2022 and we participated in the drilling of 81 (66.7 net) wells with a 100% success rate.

We delivered adjusted funds flow(1) of $280 million ($0.49 per basic share) and net income of $57 million ($0.10 per basic share). We generated free cash flow(2) of $121 million ($0.21 per basic share) during the quarter with 100% being allocated to debt repayment, reducing net debt(1) by 10% to $1.28 billion, from $1.41 billion at year-end 2021.

Operating Results

Eagle Ford and Viking Light Oil

Production in the Eagle Ford averaged 27,482 boe/d (81% oil and NGL) during Q1/2022 and generated an operating netback(2) of $133 million. We invested $28 million on exploration and development in the Eagle Ford and brought 15 (4.7 net) wells onstream. We now expect to bring approximately 16-17 net wells onstream in 2022, up from our original budget of 14 net wells.

Production in the Viking averaged 17,865 boe/d (89% oil and NGL) during Q1/2022 and generated an operating netback of $128 million. We invested $56 million on exploration and development in the Viking and brought 58 (56.5 net) wells onstream. We now expect to bring approximately 135 net wells onstream in 2022, versus our original budget of 145 new wells.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster (excluding our Clearwater development program) produced a combined 24,283 boe/d (91% oil and NGL) during Q1/2022 and generated an operating netback of $99 million. We invested $36 million on exploration and development and participated in the drilling of 3 net Bluesky wells at Peace River and 11 (10.8 net) wells at Lloydminster. In 2022, we will drill approximately 9 net Bluesky wells at Peace River and 38 net wells at Lloydminster.

Peace River Clearwater

Production in the Clearwater averaged 3,154 boe/d (100% oil) during Q1/2022 and generated an operating netback of $17 million.

We followed up our 2021 appraisal program on our Peavine acreage with an exceptional Q1/2022 drilling program. We now have all 10 wells drilled during the first quarter onstream and production has increased from zero at the beginning of 2021 to approximately 8,000 bbl/d today. During the first quarter, we successfully executed our first six extended reach horizontal ("ERH") multi-lateral wells, which are utilized to provide appropriate set-backs to residents and environmentally sensitive areas. These ERH wells are among the first of their type to be drilled in western Canada and consist of four two-mile long laterals versus a more traditional well design comprised of eight one-mile laterals. Our first three ERH wells (4-25 pad) have established average 30-day initial production rates of 1,100 bbl/d per well and are the strongest Clearwater wells drilled to date in the play. In addition, four wells (5-33 pad) were brought onstream in March/April and are expected to generate 30-day initial production rates of 300 to 400 bbl/d per well. Initial well performance continues to outperform type curve assumptions and we now have seven of the top ten initial rate wells drilled to date across the play.

As we continue to progress our development plan, we have committed to drill six additional Clearwater wells during the fourth quarter. We now intend to run a full one rig program at Peavine through year-end (previously budgeted plans had our drilling program wrapping up in September). As a result, we expect to drill 24 net wells in 2022, up from our original budget of 18 net wells. Maintaining a consistent one rig program and level loading activity in the second half of 2022 will drive further efficiencies and set the stage for continued strong operating momentum heading into 2023. Development plans going forward will be comprised of both our traditional 8-lateral well design and ERH wells.

At current commodity prices, the Clearwater generates among the strongest economics within our portfolio with payouts of less than three months and has the ability to grow organically while enhancing our free cash flow profile. To-date, we have de-risked 50 sections (of our 80-section Peavine land base) and believe the lands hold the potential for greater than 200 locations. When combined with our legacy acreage position in northwest Alberta, we estimate that over 125 sections are highly prospective for Clearwater development.

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release 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 press release for further information.

Pembina Area Duvernay Light Oil

Production in the Pembina Duvernay averaged 2,172 boe/d (82% oil and NGL) during Q1/2022. We invested $11 million on exploration and development in the Duvernay and drilled a three-well pad which is expected to be onstream in Q3/2022.

Financial Liquidity

Our net debt[(1)], which includes our credit facilities, long-term notes and working capital, totaled $1.28 billion at March 31, 2022, down from $1.41 billion at December 31, 2021. As of March 31, 2022, we had $576 million of undrawn capacity on our credit facilities, resulting in liquidity, net of working capital, of $601 million.

On April 1, 2022, we announced that we had received strong support from our lending syndicate to extend and amend our bank credit facilities. The revolving credit facilities have been extended by two years, from April 2024 to April 2026, and have been increased to US$850 million. Previously, the credit facilities totaled approximately US$815 million and were comprised of US$575 million of revolving credit facilities and a C$300 million term loan. The revolving credit facilities are not borrowing base facilities and do not require annual or semi-annual reviews.

On June 1, 2022, we intend to repurchase and cancel the remaining US$200 million principal amount of 5.625% long-term notes due 2024 at par.

Risk Management

To manage commodity price movements, we utilize various financial derivative contracts and crude-by-rail to reduce the volatility of our adjusted funds flow.

For 2022, we have entered into hedges on approximately 40% of our net crude oil exposure utilizing a combination of a 3-way option structure that provides price protection at US$57.76/bbl with upside participation to US$67.51/bbl and swaptions at US$53.50/bbl. We also have WTI-MSW differential hedges on approximately 25% of our expected net Canadian light oil exposure at US$4.43/bbl and WCS differential hedges on approximately 70% of our expected net heavy oil exposure at a WTI-WCS differential of approximately US$12.28/bbl.

For 2023, we have entered into hedges on approximately 18% of our net crude oil exposure utilizing a 3-way option structure that provides price protection at US$78.37/bbl with upside participation to US$96.12/bbl

A complete listing of our financial derivative contracts can be found in Note 16 to our Q1/2022 financial statements.

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three months ended March 31, 2022 and the related Management's Discussion and Analysis of the operating and financial results can be accessed on our website at www.baytexenergy.com and will be available shortly through SEDAR at www.sedar.com and EDGAR at www.sec.gov/edgar.shtml.

Conference Call Tomorrow
9:00 a.m. MDT (11:00 a.m. EDT)

Baytex will host a conference call tomorrow, April 29, 2022, starting at 9:00am MDT (11:00am EDT). To participate, please dial toll free in North America 1-800-319-4610 or international 1-416-915-3239. Alternatively, to listen to the conference call online, please enter http://services.choruscall.ca/links/baytex20220429.html in your web browser.

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

Advisory Regarding Forward-Looking Statements

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

Specifically, this press release contains forward-looking statements relating to but not limited to: our focus on strong capital discipline, generating free cash flow and reducing debt; that we expect to generate ~$3 Billion of cumulative free cash flow over our updated five year plan period (2022-2026); we expect to commence a share buyback program in May; we intend to repurchase and cancel the remaining US$200 million *principal amount of 5.625% long-term notes at par on June 1, 2022; we expect to generate ~$700 million ($1.25 per basic share) of free cash flow in 2022 and allocate 25% of free cash flow to a share buyback commencing in May 2022; our expected 1.0x net debt to EBITDA ratio at a US$55 WTI price when we reach our $800 million net debt target; that we will have flexibility to run our business through commodity price cycles and generate meaningful shareholder returns when our net debt target of $800 million is reached; that we expect to reach our $800 million net debt target in early 2023 and will consider steps to further enhance shareholder returns once reached; our updated guidance for 2022 exploration and development expenditures, production, royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligations; our expected exit production rate for 2022; that incremental capital for 2022 represents additional Clearwater and Eagle Ford activity and capital cost inflation; our plan to drill six additional wells at Peavine in Q4/2022 and 2-3 net incremental wells in the Eagle Ford in H2/2022; our expectations for capital cost inflation; with respect to our five-year plan (2022-2026): the oil price assumptions, expected free cash flow generation of $3 Billion and that our Clearwater play will increase to 10,000 bbl/d, generate $400 million of free cash flow and holds the potential for over 200 drilling locations that could support increasing production to over 15,000 bbl/d; through our five-year plan that we are committed to a disciplined, returns based capital allocation philosophy, targeting exploration and development expenditures at less than 50% of adjusted funds flow and expect to generate annual production growth of 2% to 4% with production reaching 95,000 boe/d in 2026; in 2022 that we expect to: bring on production 16-17 net wells in the Eagle Ford and 135 in the Viking; that we expect to drill 9 net Bluesky wells at Peace River, 38 net wells at Lloydminster and up to 24 Clearwater wells in 2022; that maintaining a one rig program in Peavine will drive further efficiencies in our business and provide strong operating momentum heading into 2023; that the Clearwater generates among the strongest economics in our portfolio with payouts of less than three months and has the ability to grow organically while enhancing our free cash flow profile; we have over 125 sections that are highly prospective for Clearwater development; a three well pad in the Duvernay is expected to be onstream in Q3/2022; we use financial derivative contracts and crude-by-rail to reduce adjusted funds flow volatility; the percentage of our net exposure to crude oil, the WTI-MSW differential and WCS differential that we have hedged for 2022 and the percentage of our net exposure to crude oil that we have hedged for 2023.*

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; TSX approval of our share buyback program; 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 and 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, filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission and in our other public filings.

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

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

Specified Financial Measures

In this press release, we refer to certain financial measures (such as free cash flow, operating netback, average royalty rate and total sales, net of blending and other expense) which do not have any standardized meaning prescribed by IFRS. While free cash flow and operating netback are commonly used in the oil and gas industry, our determination of these measures may not be comparable with calculations of similar measures for other issuers. In addition, this press release contains the terms adjusted funds flow and net debt, which are considered capital management measures.

Non-GAAP Financial Measures

Total sales, net of blending and other expense

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

The following table reconciles total sales, net of blending and other expense and operating netback to petroleum and natural gas sales.

	Three Months Ended March 31	
($ thousands)	**2022**	2021
Petroleum and natural gas sales	**$ 673,825**	$ 384,702
Blending and other expense	**(41,440)**	(17,120)
Total sales, net of blending and other expense	**632,385**	367,582
Royalties	**(122,720)**	(66,950)
Operating expense	**(100,766)**	(80,548)
Transportation expense	**(9,215)**	(8,788)
Operating netback	**$ 399,684**	$ 211,296

Free cash flow

Free cash flow is not a measurement based on GAAP in Canada. We define free cash flow as 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. Our determination of free cash flow may not be comparable to other issuers. We use free cash flow to evaluate funds available for debt repayment, common share repurchases, potential future dividends and acquisition and disposition opportunities.

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

	Three Months Ended March 31	
($ thousands)	**2022**	2021
Cash flows from operating activities	**$ 198,974**	$ 120,980
Change in non-cash working capital	**77,340**	34,185
Additions to exploration and evaluation assets	**(3,559)**	(216)
Additions to oil and gas properties	**(150,263)**	(83,372)
Payments on lease obligations	**(1,174)**	(1,082)
Free cash flow	**$ 121,318**	$ 70,495

Non-GAAP Financial Ratios

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 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. 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 equal to operating netback divided by barrels of oil equivalent sales volume for the applicable period and is used to assess our operating performance on a unit of production basis.

Capital Management Measures

Net debt

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

The following table summarizes our calculation of net debt.

($ thousands)		**March 31, 2022**		December 31, 2021
Credit facilities	**$**	**425,675**	$	505,171
Unamortized debt issuance costs - Credit facilities [(1)]		**1,183**		1,343
Long-term notes		**863,180**		874,527
Unamortized debt issuance costs - Long-term notes [(1)]		**10,700**		11,393
Trade and other payables		**257,683**		190,692
Trade and other receivables		**(282,741)**		(173,409)
Net debt	**$**	**1,275,680**	$	1,409,717

(1) Unamortized debt issuance costs were obtained from Note 6 Credit Facilities and Note 7 Long-term Notes from the Consolidated Financial Statements for the three months ended March 31, 2022.

Adjusted funds flow

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

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

	Three Months Ended March 31			
($ thousands)		**2022**		2021
Cash flow from operating activities	**$**	**198,974**	$	120,980
Change in non-cash working capital		**77,340**		34,185
Asset retirement obligations settled		**3,293**		1,417
Adjusted funds flow	**$**	**279,607**	$	156,582

Advisory Regarding Oil and Gas Information

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

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

Throughout this news release, "oil and NGL" refers to heavy oil, bitumen, light and medium oil, tight oil, condensate and natural gas liquids ("NGL") product types as defined by NI 51-101. The following table shows Baytex's disaggregated production volumes for the three months ended March 31, 2022. The NI 51-101 product types are included as follows: "Heavy Oil" - heavy oil and bitumen, "Light and Medium Oil" - light and medium oil, tight oil and condensate, "NGL" - natural gas liquids and "Natural Gas" - shale gas and conventional natural gas. All production from our Peavine asset is 100% Heavy Oil.

	Three Months Ended March 31, 2022				
	Heavy Oil (bbl/d)	**Light and Medium Oil (bbl/d)**	**NGL (bbl/d)**	**Natural Gas (Mcf/d)**	**Oil Equivalent (boe/d)**
Canada – Heavy					
Peace River	11,587	5	29	11,125	13,475
Lloydminster	10,495	15	—	1,787	10,808
Peavine	3,154	—	—	—	3,154
Canada - Light					
Viking	—	15,694	188	11,894	17,865
Duvernay	—	992	789	2,343	2,172
Remaining Properties	—	867	929	24,694	5,911
United States					
Eagle Ford	—	16,492	5,701	31,731	27,482
Total	25,236	34,065	7,636	83,574	80,867

This presentation discloses drilling inventory and potential drilling locations. Drilling inventory and drilling locations refers to Baytex's proved, probable and unbooked locations. Proved locations and probable locations account for drilling locations in our inventory that have associated proved and/or probable reserves. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves. Unbooked locations are farther away from existing wells and, therefore, there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty whether such wells will result in additional oil and gas reserves, resources or production. Of the 200 or more potential drilling locations identified in the Clearwater, as at December 31, 2021, 4 are proved locations, 5 are probable locations and the remainder are unbooked locations.

Baytex Energy Corp.

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

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

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BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the three months ended March 31, 2022 and 2021
Dated April 28, 2022

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three months ended March 31, 2022. This information is provided as of April 28, 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 ended March 31, 2022 ("Q1/2022") has been compared with the results for the three months ended March 31, 2021 ("Q1/2021"). This MD&A should be read in conjunction with the Company's condensed consolidated interim financial statements ("consolidated financial statements") for the three months ended March 31, 2022, its audited comparative consolidated financial statements for the years ended December 31, 2021 and 2020, together with the accompanying notes, and its Annual Information Form 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.

FIRST QUARTER HIGHLIGHTS

Baytex delivered strong operating and financial results in Q1/2022. Energy prices strengthened to multi-year highs due to elevated uncertainty of global oil and natural gas supply after Russia's invasion of Ukraine in addition to limited production growth reflecting oil and gas producers' capital discipline. As a result, the average WTI benchmark price for Q1/2022 was US$94.29/bbl which was US$36.45/bbl higher than Q1/2021 when WTI averaged US$57.84/bbl. With higher commodity prices, we generated adjusted funds flow(1) of $279.6 million and free cash flow(2) of $121.3 million which contributed to a $134.0 million reduction in net debt(1). Strong well performance across all of our assets resulted in production of 80,867 boe/d which was consistent with our annual guidance range of 80,000 - 83,000 boe/d.

Exploration and development expenditures were $153.8 million for Q1/2022 with $126.1 million invested in Canada and $27.7 million in the U.S. In Canada, we brought 12 (12.0 net) heavy oil wells and 58 (56.5 net) light oil wells on production during Q1/2022 which resulted in production of 53,385 boe/d that increased 1,346 boe/d from Q1/2021. In the U.S., we brought 15 (4.7 net) wells on production during Q1/2022 which resulted in production of 27,482 boe/d or 741 boe/d higher than Q1/2021.

Adjusted funds flow(1) of $279.6 million in Q1/2022 was $123.0 million higher than Q1/2021 as a result of higher benchmark prices. The increase in commodity prices was the primary factor that resulted in a $188.4 million increase in operating netback for Q1/2022 relative to Q1/2021. Our strong operating and financial results contributed to net income of $56.9 million for Q1/2022 compared to a net loss of $35.4 million for Q1/2021.

(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.

We used our free cash flow[1] of $121.3 million generated during Q1/2022 to reduce our debt. Net debt[2] of $1.28 billion at March 31, 2022 was $134.0 million lower compared to $1.41 billion at December 31, 2021. The decrease in net debt also reflects the strengthening of the Canadian dollar during Q1/2022 to 1.2484 CAD/USD at March 31, 2022 compared to 1.2656 CAD/USD at December 31, 2021.

(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.

2022 GUIDANCE

The following table compares our revised 2022 annual guidance to our previously announced guidance. Operational success, the continued strong economics of our drilling program as well as inflationary pressures being experienced throughout our industry have caused us to review our capital program for the year.

We are now forecasting 2022 exploration and development expenditures of $450 to $500 million, up from our original guidance of $400 - $450 million which was set anticipating WTI of approximately US$65/bbl for 2022. The incremental capital reflects additional activity on our Clearwater lands and the Eagle Ford as well as expected capital cost inflation. With continued strong operating momentum and production growth on our Clearwater lands, we are increasing our production guidance for 2022 to 83,000 to 85,000 boe/d. We also adjusted several of our cost assumptions to reflect higher commodity pricing, inflationary pressures and higher production volumes. Interest expense guidance is lower as we expect to reduce net debt during the remainder of 2022.

	Original Annual Guidance [1]	Revised Annual Guidance
Exploration and development expenditures	$400 - $450 million	$450 - $500 million
Production (boe/d)	80,000 - 83,000	83,000 - 85,000
Expenses:		
Average royalty rate[2]	18.5% - 19.0%	20.0% - 20.5%
Operating[3]	$12.25 - $13.00/boe	$13.00 - $13.50/boe
Transportation[3]	$1.20 - $1.30/boe	$1.30 - $1.40/boe
General and administrative[3]	$43 million ($1.45/boe)	$43 million ($1.40/boe)
Interest[3]	$80 million ($2.70/boe)	$75 million ($2.45/boe)
Leasing expenditures	$3 million	no change
Asset retirement obligations	$20 million	no change

(1) As announced on December 1, 2021.
(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) 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.

RESULTS OF OPERATIONS

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

Production

	Three Months Ended March 31					
	2022			2021		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**17,573**	**16,492**	**34,065**	19,228	16,202	35,430
Heavy oil	**25,236**	**—**	**25,236**	21,989	—	21,989
Natural Gas Liquids (NGL)	**1,935**	**5,701**	**7,636**	1,970	4,268	6,238
Total liquids (bbl/d)	**44,744**	**22,193**	**66,937**	43,187	20,470	63,657
Natural gas (mcf/d)	**51,843**	**31,731**	**83,574**	53,109	37,630	90,739
Total production (boe/d)	**53,385**	**27,482**	**80,867**	52,039	26,741	78,780
Production Mix						
Segment as a percent of total	**66 %**	**34 %**	**100 %**	66 %	34 %	100 %
Light oil and condensate	**33 %**	**60 %**	**42 %**	37 %	61 %	45 %
Heavy oil	**47 %**	**— %**	**31 %**	42 %	— %	28 %
NGL	**4 %**	**21 %**	**9 %**	4 %	16 %	8 %
Natural gas	**16 %**	**19 %**	**18 %**	17 %	23 %	19 %

Production was 80,867 boe/d for Q1/2022 compared to 78,780 boe/d for Q1/2021. Total production was higher in Q1/2022 compared to Q1/2021 due to our successful development programs in the U.S. and Canada including strong well results from our Clearwater development program.

In Canada, production of 53,385 boe/d for Q1/2022 was higher compared to 52,039 boe/d for Q1/2021. Our successful 2021 development program and strong well performance from our Clearwater development program has resulted in production for Q1/2022 that was 1,346 boe/d higher relative to Q1/2021.

In the U.S., production of 27,482 boe/d for Q1/2022 was higher than 26,741 boe/d for Q1/2021. Limited development activity throughout 2020 resulted in lower production levels in the U.S. during Q1/2021 when activity began to increase as commodity prices stabilized. We initiated production from 15 (4.7 net) wells during Q1/2022 compared to 24 (7.0 net) wells during the comparative period in 2021.

Total production of 80,867 boe/d for Q1/2022 is consistent with expectations and our original annual guidance range of 80,000 - 83,000 boe/d. Our revised annual guidance of 83,000 - 85,000 boe/d for 2022 reflects our strong operating momentum to date and production growth on our Clearwater lands.

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 traded at multi-year highs during Q1/2022. Russia's invasion of Ukraine has led to significant economic sanctions and uncertainty over oil supply from Russia while global supply growth has been limited with reduced capital investment. Oil demand continues to improve as global economic activity increases and economies recover from the pandemic. These factors resulted in the WTI benchmark price averaging US$94.29/bbl for Q1/2022 which was US$36.45/bbl higher relative to Q1/2021 when WTI averaged US$57.84/bbl.

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$96.72/bbl during Q1/2022 which is US$37.36/bbl higher than US$59.36/bbl during Q1/2021. The MEH benchmark trades at a premium to WTI as a result of access to global markets. For Q1/2022 the premium of US$2.43/bbl to WTI was larger than a US$1.52/bbl premium to WTI during Q1/2021 as a result of Russia's invasion of Ukraine and heightened concerns over global oil supply.

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 $115.66/bbl during Q1/2022 compared to $66.58/bbl during Q1/2021. Edmonton par traded at a discount to WTI of US$2.94/bbl for Q1/2022 which is narrower compared to a discount of US$5.27/bbl for Q1/2021 due to higher demand for Canadian light oil in Q1/2022.

We compare the price received for our heavy oil production in Canada to the WCS heavy oil benchmark. The WCS heavy oil price for Q1/2022 averaged $100.99/bbl compared to $57.46/bbl for the same period of 2021. The WCS heavy oil differential was US$14.53/bbl in Q1/2022 which is wider compared to US$12.46/bbl for Q1/2021. Floods in Western Canada in late 2021 caused a temporary shut down of the Trans Mountain pipeline and resulted in a WCS differential of US$17.38/bbl in January 2022.

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$4.95/mmbtu for Q1/2022 which is higher than US$2.69/mmbtu for Q1/2021. Strong demand and lower U.S. production resulted in reduced natural gas inventory levels which contributed to higher NYMEX benchmark prices for Q1/2022 relative to Q1/2021.

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. Lower production and an increased demand for natural gas resulted in reduced inventory levels in Canada and contributed to stronger AECO benchmark pricing in 2022 relative to 2021. The AECO benchmark averaged $4.59/mcf during Q1/2022 which is higher than $2.93/mcf for Q1/2021.

The following tables compare select benchmark prices and our average realized selling prices for the three months ended March 31, 2022 and 2021.

	Three Months Ended March 31		
	2022	2021	Change
Benchmark Averages			
WTI oil (US$/bbl)(1)	**94.29**	57.84	36.45
MEH oil (US$/bbl)(2)	**96.72**	59.36	37.36
MEH oil differential to WTI (US$/bbl)	**2.43**	1.52	0.91
Edmonton par oil ($/bbl)(3)	**115.66**	66.58	49.08
Edmonton par oil differential to WTI (US$/bbl)	**(2.94)**	(5.27)	2.33
WCS heavy oil ($/bbl)(4)	**100.99**	57.46	43.53
WCS heavy oil differential to WTI (US$/bbl)	**(14.53)**	(12.46)	(2.07)
AECO natural gas price ($/mcf)(5)	**4.59**	2.93	1.66
NYMEX natural gas price (US$/mmbtu)(6)	**4.95**	2.69	2.26
CAD/USD average exchange rate	**1.2661**	1.2663	(0.0002)

(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.

	Three Months Ended March 31					
	2022			2021		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl)[1]	**$ 113.91**	**$ 121.82**	**$ 117.74**	$ 64.46	$ 72.42	$ 68.10
Heavy oil, net of blending and other expense ($/bbl)[2]	**89.38**	**—**	**89.38**	46.45	—	46.45
NGL ($/bbl)[1]	**42.96**	**42.89**	**42.91**	24.61	34.21	31.18
Natural gas ($/mcf)[1]	**4.64**	**6.06**	**5.17**	3.03	7.84	5.02
Total sales, net of blending and other expense ($/boe)[2]	**$ 85.81**	**$ 89.00**	**$ 86.89**	$ 47.47	$ 60.36	$ 51.84

(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.

Average Realized Sales Prices

Our total sales, net of blending and other expense per boe was $86.89/boe for Q1/2022 compared to $51.84/boe for Q1/2021. In Canada, our realized price of $85.81/boe for Q1/2022 was $38.34/boe higher than $47.47/boe for Q1/2021. Our realized price in the U.S. was $89.00/boe in Q1/2022 which is $28.64/boe higher than $60.36/boe in Q1/2021. The increase in our realized price in Canada and the U.S. for Q1/2022 was a result of higher North American benchmark prices relative to the same period of 2021.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Our realized light oil and condensate price was $113.91/bbl for Q1/2022 compared to $64.46/bbl for Q1/2021. Our realized light oil and condensate price for Q1/2022 increased with the improvement in the benchmark price and represents a discount of $1.75/bbl to the Edmonton par price which is similar to a discount of $2.12/bbl for Q1/2021.

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 $121.82/bbl for Q1/2022 compared to $72.42/bbl for Q1/2021. Expressed in U.S. dollars, our realized light oil and condensate price of US$96.22/bbl for Q1/2022 represents a discount to MEH of US$0.50/bbl. Production increased as benchmark prices strengthened during Q1/2022 which resulted in stronger price realizations relative to Q1/2021 when our discount to MEH was US$2.17/bbl.

Our realized heavy oil price, net of blending and other expense averaged $89.38/bbl in Q1/2022 compared to $46.45/bbl in Q1/2021. Our realized heavy oil, net of blending and other expense for Q1/2022 was $42.93/bbl higher relative to Q1/2021 which is consistent with a $43.53/bbl increase in the WCS benchmark price relative to Q1/2021.

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 for the underlying products. Our realized NGL price was $42.91/bbl in Q1/2022 or 36% of WTI (expressed in Canadian dollars) compared to $31.18/bbl or 43% of WTI (expressed in Canadian dollars) in Q1/2021. Our realized NGL price was lower as a percentage of WTI in Q1/2022 relative to the same period of 2021 when a winter storm in Texas disrupted supply and resulted in higher pricing for our U.S. NGL production.

We compare our realized natural gas price in Canada to the AECO benchmark price. Our realized natural gas price was $4.64/mcf for Q1/2022 compared to $3.03/mcf in Q1/2021. 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$4.79/mcf for Q1/2022 compared to US$6.19/mcf for Q1/2021. Our realized natural gas price for Q1/2022 was lower relative to Q1/2021 due to fluctuations in the NYMEX daily index caused by severe events which disrupted supply and caused increased demand on the U.S. Gulf coast during 2021.

PETROLEUM AND NATURAL GAS SALES

	Three Months Ended March 31					
	2022			2021		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 180,156**	**$ 180,820**	**$ 360,976**	$ 111,546	$ 105,596	$ 217,142
Heavy oil	**244,439**	**—**	**244,439**	109,038	—	109,038
NGL	**7,483**	**22,007**	**29,490**	4,364	13,142	17,506
Total oil sales	**432,078**	**202,827**	**634,905**	224,948	118,738	343,686
Natural gas sales	**21,626**	**17,294**	**38,920**	14,475	26,541	41,016
Total petroleum and natural gas sales	**453,704**	**220,121**	**673,825**	239,423	145,279	384,702
Blending and other expense	**(41,440)**	**—**	**(41,440)**	(17,120)	—	(17,120)
Total sales, net of blending and other expense(1)	**$ 412,264**	**$ 220,121**	**$ 632,385**	$ 222,303	$ 145,279	$ 367,582

(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 $632.4 million for Q1/2022 increased $264.8 million from $367.6 million reported for Q1/2021. The increase in total sales is a primarily a result of higher realized pricing due to the increase in benchmark pricing along with a modest increase in production due to our successful development programs in the U.S. and Canada.

In Canada, total sales, net of blending and other expense, was $412.3 million for Q1/2022 which is an increase of $190.0 million from $222.3 million reported for Q1/2021. The increase in total petroleum and natural gas sales was primarily due to higher realized pricing for Q1/2022 relative to Q1/2021. Our increased realized price resulted in a $184.2 million increase in total sales, net of blending and other expense, while a modest increase in production resulted in a $5.8 million increase in total sales, net of blending and other expense, relative to Q1/2021.

In the U.S., petroleum and natural gas sales were $220.1 million for Q1/2022 which is an increase of $74.8 million from $145.3 million reported for Q1/2021. Total petroleum and natural gas sales increased $70.8 million due to higher realized pricing for Q1/2022 relative to Q1/2021 while higher production resulted in a $4.0 million increase in total sales, net of blending and other expense relative to Q1/2021.

ROYALTIES

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues or on operating netbacks less capital investment for specific heavy oil projects and are generally expressed as a percentage of total sales, net of blending and other expense. The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction. The following table summarizes our royalties and royalty rates for the three months ended March 31, 2022 and 2021.

	Three Months Ended March 31					
	2022			2021		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 57,676**	**$ 65,044**	**$ 122,720**	$ 24,664	$ 42,286	$ 66,950
Average royalty rate(1)(2)	**14.0 %**	**29.5 %**	**19.4 %**	11.1 %	29.1 %	18.2 %
Royalties per boe(3)	**$ 12.00**	**$ 26.30**	**$ 16.86**	$ 5.27	$ 17.57	$ 9.44

(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 Q1/2022 were $122.7 million or 19.4% of total sales, net of blending and other expense compared to $67.0 million or 18.2% for Q1/2021. Total royalty expense was higher for Q1/2022 due to higher total sales, net of blending and other expense, relative to Q1/2021. Our royalty rate of 19.4% for Q1/2022 was also higher than 18.2% for Q1/2021 due to a higher royalty rate on our Canadian properties as a result of higher commodity prices. Our average royalty rate of 19.4% for Q1/2022 is slightly below our revised annual guidance range of 20.0% - 20.5% for 2022 as we expect higher commodity pricing during the remainder of the year.

Our Canadian royalty rate of 14.0% for Q1/2022 was higher than 11.1% for Q1/2021 due to higher benchmark commodity prices which resulted in a higher royalty rate on our Canadian properties in 2022 relative to 2021. In the U.S., royalties averaged 29.5% of total sales for Q1/2022, which is consistent with 29.1% for Q1/2021 as the royalty rate on our U.S. production does not vary with price but can vary across our acreage.

OPERATING EXPENSE

	Three Months Ended March 31					
	2022			2021		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 78,540**	**$ 22,226**	**$ 100,766**	$ 61,361	$ 19,187	$ 80,548
Operating expense per boe(1)	**$ 16.35**	**$ 8.99**	**$ 13.85**	$ 13.10	$ 7.97	$ 11.36

(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 $100.8 million ($13.85/boe) for Q1/2022 compared to $80.5 million ($11.36/boe) for Q1/2021. Total operating expense for Q1/2022 increased with production relative to Q1/2021. Operating expense of $13.85/boe for Q1/2022 was above our revised annual guidance range of $13.00 - $13.50/boe largely due to higher fuel, electricity and hauling costs as these costs are tied to the price of oil and gas which have increased above our original budget.

In Canada, operating expense was $78.5 million ($16.35/boe) for Q1/2022 compared to $61.4 million ($13.10/boe) for Q1/2021. Operating expense in Canada has increased for Q1/2022 relative to Q1/2021 due to higher production along with an increase in per unit operating expenses. U.S. operating expense was $22.2 million ($8.99/boe) for Q1/2022 compared to $19.2 million ($7.97/boe) for Q1/2021. Higher operating expense in Q1/2022 is a result of higher production along with an increase in per unit operating expenses relative to Q1/2021. Expressed in U.S. dollars, per unit operating expense was US$7.10/boe in Q1/2022 which was higher than US$6.29/boe for Q1/2021. The increase in per unit operating expense in Canada and the U.S. was primarily a result of higher fuel, electricity and hauling costs in Q1/2022 relative to Q1/2021.

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 three months ended March 31, 2022 and 2021.

	Three Months Ended March 31					
	2022			2021		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 9,215**	**$ —**	**$ 9,215**	$ 8,788	$ —	$ 8,788
Transportation expense per boe(1)	**$ 1.92**	**$ —**	**$ 1.27**	$ 1.88	$ —	$ 1.24

(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 $9.2 million ($1.27/boe) for Q1/2022 which is consistent with $8.8 million ($1.24/boe) for Q1/2021. Per unit transportation expense of $1.27/boe for Q1/2022 is consistent with expectations and our revised annual guidance of $1.30 - $1.40/boe.

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 $41.4 million for Q1/2022 compared to $17.1 million for Q1/2021. Higher blending and other expense reflects an increase in the price of condensate purchased as diluent along with an increase in heavy oil pipeline shipments in Q1/2022 due to higher heavy oil production and lower rail deliveries relative to Q1/2021.

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 three months ended March 31, 2022 and 2021.

	Three Months Ended March 31		
($ thousands)	**2022**	2021	Change
Realized financial derivatives loss			
Crude oil	**$ (79,526)**	$ (20,041)	$ (59,485)
Natural gas	**(4,840)**	(727)	(4,113)
Total	**$ (84,366)**	$ (20,768)	$ (63,598)
Unrealized financial derivatives (loss) gain			
Crude oil	**$ (139,318)**	$ (85,470)	$ (53,848)
Natural gas	**(16,634)**	(1,387)	(15,247)
Equity total return swap ("Equity TRS")	**(309)**	873	(1,182)
Total	**$ (156,261)**	$ (85,984)	$ (70,277)
Total financial derivatives (loss) gain			
Crude oil	**$ (218,844)**	$ (105,511)	$ (113,333)
Natural gas	**(21,474)**	(2,114)	(19,360)
Equity TRS	**(309)**	873	(1,182)
Total	**$ (240,627)**	$ (106,752)	$ (133,875)

We recorded total financial derivative loss of $240.6 million for Q1/2022 compared to a loss of $106.8 million for Q1/2021. The realized financial derivatives loss of $84.4 million for Q1/2022 was a result of the market prices for crude oil and natural gas settling at levels above those set in our derivative contracts. The unrealized loss of $156.3 million for Q1/2022 was primarily a result of the increase in forecasted crude oil pricing used to revalue our crude oil contracts in place at March 31, 2022 relative to December 31, 2021 along with the valuation of new contracts entered during the period. The fair value of our financial derivative contracts resulted in a net liability of $281.6 million at March 31, 2022 compared to a net liability of $125.4 million at December 31, 2021.

We had the following commodity financial derivative contracts as at April 28, 2022.

	Period	Volume	Price/Unit[1]	Index
Oil				
Basis Swap	Apr 2022 to Dec 2022	12,000 bbl/d	WTI less US$12.40/bbl	WCS
Basis Swap	Apr 2022 to Jun 2022	1,000 bbl/d	WTI less US$3.00/bbl	MSW
Basis Swap	Apr 2022 to Dec 2022	6,000 bbl/d	WTI less US$3.91/bbl	MSW
Basis Swap	Jul 2022 to Dec 2022	750 bbl/d	WTI less US$2.30/bbl	MSW
Fixed Sell	Apr 2022 to Dec 2022	10,000 bbl/d	US$53.50/bbl	WTI
3-way option[2]	Apr 2022 to Dec 2022	1,500 bbl/d	US$40.00/US$50.00/US$58.10	WTI
3-way option[2]	Apr 2022 to Dec 2022	2,000 bbl/d	US$46.00/US$56.00/US$66.72	WTI
3-way option[2]	Apr 2022 to Dec 2022	2,500 bbl/d	US$47.00/US$57.00/US$67.00	WTI
3-way option[2]	Apr 2022 to Dec 2022	2,500 bbl/d	US$50.00/US$60.00/US$70.00	WTI
3-way option[2]	Apr 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]	Jan 2023 to Dec 2023	2,500 bbl/d	US$60.00/US$75.00/US$91.54	WTI
3-way option[2]	Jan 2023 to Dec 2023	2,500 bbl/d	US$65.00/US$85.00/US$100.00	WTI
3-way option[2]	Jan 2023 to Dec 2023	2,500 bbl/d	US$65.00/US$85.00/US$106.50	WTI
Natural Gas				
Fixed Sell	Apr 2022 to Dec 2022	5,000 GJ/d	$2.53/GJ	AECO 7A
Fixed Sell	Apr 2022 to Dec 2022	14,250 GJ/d	$2.84/GJ	AECO 5A
Fixed Sell	Apr 2022 to Dec 2022	1,000 mmbtu/d	US$2.94/mmbtu	NYMEX
3-way option[2]	Apr 2022 to Dec 2022	2,500 mmbtu/d	US$2.25/US$2.75/US$3.06	NYMEX
3-way option[2]	Apr 2022 to Dec 2022	1,500 mmbtu/d	US$2.60/US$2.91/US$3.56	NYMEX
3-way option[2]	Apr 2022 to Dec 2022	2,500 mmbtu/d	US$2.60/US$3.00/US$3.83	NYMEX
3-way option[2]	Apr 2022 to Dec 2022	2,500 mmbtu/d	US$2.65/US$2.90/US$3.40	NYMEX
3-way option[2]	Apr 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 put, a bought put and a sold call. 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.

OPERATING NETBACK

The following table summarizes our operating netback on a per boe basis for our Canadian and U.S. operations for the three months ended March 31, 2022 and 2021.

	Three Months Ended March 31					
	2022			2021		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**53,385**	**27,482**	**80,867**	52,039	26,741	78,780
Operating netback:						
Total sales, net of blending and other expense[1]	**$ 85.81**	**$ 89.00**	**$ 86.89**	$ 47.47	$ 60.36	$ 51.84
Less:						
Royalties[2]	**(12.00)**	**(26.30)**	**(16.86)**	(5.27)	(17.57)	(9.44)
Operating expense[2]	**(16.35)**	**(8.99)**	**(13.85)**	(13.10)	(7.97)	(11.36)
Transportation expense[2]	**(1.92)**	**—**	**(1.27)**	(1.88)	—	(1.24)
Operating netback[1]	**$ 55.54**	**$ 53.71**	**$ 54.91**	$ 27.22	$ 34.82	$ 29.80
Realized financial derivatives (loss) gain[3]	**—**	**—**	**(11.59)**	—	—	(2.93)
Operating netback after financial derivatives[1]	**$ 55.54**	**$ 53.71**	**$ 43.32**	$ 27.22	$ 34.82	$ 26.87

(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 of $54.91/boe for Q1/2022 was higher than $29.80/boe for Q1/2021 due to the increase in benchmark pricing in Canada and the U.S. which resulted in higher per unit sales net of royalties. Total operating and transportation expense of $15.12/boe for Q1/2022 was higher than $12.60/boe for Q1/2021 due to higher fuel, electricity and hauling costs. Including realized gains and losses on financial derivatives our operating netback was $43.32/boe for Q1/2022 compared to $26.87/boe for Q1/2021.

GENERAL AND ADMINISTRATIVE EXPENSE

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

The following table summarizes our G&A expense for the three months ended March 31, 2022 and 2021.

	Three Months Ended March 31		
($ thousands except for per boe)	**2022**	2021	Change
Gross general and administrative expense	**$ 13,507**	$ 9,462	$ 4,045
Overhead recoveries	**(1,825)**	(729)	(1,096)
General and administrative expense	**$ 11,682**	$ 8,733	$ 2,949
General and administrative expense per boe[1]	**$ 1.61**	$ 1.23	$ 0.38

(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 $11.7 million ($1.61/boe) for Q1/2022 compared to $8.7 million ($1.23/boe) for Q1/2021. G&A expense for Q1/2022 was higher relative to Q1/2021 due to higher staffing costs associated with increased exploration and development expenditures in Canada during Q1/2022.

G&A expense of $1.61/boe for Q1/2022 is consistent with expectations and is above our revised annual guidance of $1.40/boe for 2022 as a higher proportion of annual costs are incurred in the first quarter and we are forecasting production to increase over the remainder of 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 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 three months ended March 31, 2022 and 2021.

	Three Months Ended March 31		
($ thousands except for per boe)	**2022**	2021	Change
Interest on credit facilities	**$ 3,039**	$ 3,336	$ (297)
Interest on long-term notes	**17,344**	21,007	(3,663)
Interest on lease obligations	**44**	60	(16)
Cash interest	**$ 20,427**	$ 24,403	$ (3,976)
Accretion of debt issue costs	**695**	749	(54)
Accretion of asset retirement obligations	**3,122**	2,298	824
Financing and interest expense	**$ 24,244**	$ 27,450	$ (3,206)
Cash interest per boe[1]	**$ 2.81**	$ 3.44	$ (0.63)
Financing and interest expense per boe[1]	**$ 3.33**	$ 3.87	$ (0.54)

(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 $24.2 million ($3.33/boe) for Q1/2022 compared to $27.5 million ($3.87/boe) for Q1/2021. Lower debt levels have resulted in reduced financing and interest expense in Q1/2022 relative to Q1/2021.

Cash interest of $20.4 million ($2.81/boe) for Q1/2022 is lower than $24.4 million ($3.44/boe) for Q1/2021 as we had less debt outstanding during 2022. The interest on our U.S. dollar denominated long-term notes was lower as the average principal amount outstanding was lower during Q1/2022 due to the repurchase and redemption of US$200.0 million of long-term notes in 2021. Interest on our credit facilities in Q1/2022 was relatively consistent with the same period of 2021. The weighted average interest rate applicable to our credit facilities was 2.4% Q1/2022 compared to 2.1% for Q1/2021.

Financing and interest expense for Q1/2022 was lower than Q1/2021 which was primarily the result of the repurchase and redemption of long-term notes in 2021 and also reflects a higher discount rate used to accrete our asset retirement obligations in Q1/2022.

Cash interest expense of $2.81/boe for Q1/2022 is above our revised annual guidance of $2.45/boe for 2022 as we expect a reduction in our net debt during the remainder of the year along with higher production.

EXPLORATION AND EVALUATION EXPENSE

Exploration and evaluation ("E&E") expense is related to the expiry of leases and the de-recognition of costs for exploration programs that have not demonstrated commercial viability and technical feasibility. E&E expense will vary depending on the timing of expiring leases, the accumulated costs of the expiring leases and the economic facts and circumstances related to the Company's exploration programs. Exploration and evaluation expense was $3.6 million for Q1/2022 compared to $0.9 million for Q1/2021.

DEPLETION AND DEPRECIATION

Depletion and depreciation expense varies with the carrying amount of the Company's oil and gas properties, the amount of proved plus probable reserves volumes and the rate of production for the period. The following table summarizes depletion and depreciation expense for the three months ended March 31, 2022 and 2021.

	Three Months Ended March 31		
($ thousands except for per boe)	**2022**	2021	Change
Depletion	**$ 139,446**	$ 100,739	$ 38,707
Depreciation	**1,345**	1,273	72
Depletion and depreciation	**$ 140,791**	$ 102,012	$ 38,779
Depletion and depreciation per boe(1)	**$ 19.34**	$ 14.39	$ 4.95

(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 $140.8 million ($19.34/boe) for Q1/2022 compared to $102.0 million ($14.39/boe) for Q1/2021. Total depletion and depreciation expense as well as the depletion rate per boe were higher in Q1/2022 relative to Q1/2021 as a result of $1.5 billion of impairment reversals recorded during 2021 which increased the depletable base of our U.S and Canadian assets.

IMPAIRMENT

We did not identify indicators of impairment or impairment reversal for any of our cash generating units ("CGU") at March 31, 2022.

2021 Impairment Reversals

We identified indicators of impairment reversal at June 30, 2021 and December 31, 2021 due to the increase in forecasted commodity prices in addition to changes in proved plus probable reserves and we recorded a total impairment reversal of $1.5 billion. At June 30, 2021 we recorded a $1.1 billion impairment reversal as the estimated recoverable amount of our six CGUs exceeded their carrying values. At December 31, 2021 we recorded a $0.4 billion impairment reversal as the estimated recoverable amount of three CGUs exceeded their carrying amounts.

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

We recorded SBC expense of $3.9 million for Q1/2022 which is consistent with $3.0 million for Q1/2021. The total expense for Q1/2022 is comprised of non-cash compensation expense of $1.7 million related to the Share Award Incentive Plan and cash compensation expense of $2.2 million related to the Incentive Award Plan and the Deferred Share Unit Plan.

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. The long-term 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)		Three Months Ended March 31 2022		2021		Change
Unrealized foreign exchange gain	$	**(14,548)**	$	(2,530)	$	(12,018)
Realized foreign exchange loss (gain)		**203**		(275)		478
Foreign exchange gain	$	**(14,345)**	$	(2,805)	$	(11,540)
CAD/USD exchange rates:						
At beginning of period		**1.2656**		1.2755		
At end of period		**1.2484**		1.2572		

We recorded a foreign exchange gain of $14.3 million for Q1/2022 compared to a gain of $2.8 million for Q1/2021.

The unrealized foreign exchange gain of $14.5 million for Q1/2022 is primarily related to changes in the reported amount of our long-term notes due to a strengthening of the Canadian dollar relative to the U.S. dollar at March 31, 2022 compared to December 31, 2021. The unrealized foreign exchange gain for Q1/2021 relates to changes in the reported amount of our long-term notes and intercompany notes outstanding at March 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 loss of $0.2 million for Q1/2022 compared to a gain of $0.3 million for Q1/2021.

INCOME TAXES

($ thousands)		Three Months Ended March 31 2022		2021		Change
Current income tax expense (recovery)	$	**910**	$	(160)	$	1,070
Deferred income tax (recovery) expense		**(67,332)**		5,664		(72,996)
Total income tax (recovery) expense	$	**(66,422)**	$	5,504	$	(71,926)

Current income tax expense was $0.9 million for Q1/2022 compared to a recovery of $0.2 million for Q1/2021.

We recorded a deferred tax recovery of $67.3 million for Q1/2022 compared to an expense of $5.7 million for Q1/2021. The deferred tax recovery recorded in Q1/2022 is primarily related to the effect of an internal debt restructuring offset by the income generated in our U.S. operations for the period. The deferred tax expense for Q1/2021 reflects income generated in our U.S. operations for the period.

As disclosed in the 2021 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.

NET INCOME (LOSS) AND ADJUSTED FUNDS FLOW

The components of adjusted funds flow and net income or loss for the three months ended March 31, 2022 and 2021 are set forth in the following table.

	Three Months Ended March 31		
($ thousands)	**2022**	2021	Change
Petroleum and natural gas sales	**$ 673,825**	$ 384,702	$ 289,123
Royalties	**(122,720)**	(66,950)	(55,770)
Revenue, net of royalties	**551,105**	317,752	233,353
Expenses			
Operating	**(100,766)**	(80,548)	(20,218)
Transportation	**(9,215)**	(8,788)	(427)
Blending and other	**(41,440)**	(17,120)	(24,320)
Operating netback(1)	**$ 399,684**	$ 211,296	$ 188,388
General and administrative	**(11,682)**	(8,733)	(2,949)
Cash interest	**(20,427)**	(24,403)	3,976
Realized financial derivatives loss	**(84,366)**	(20,768)	(63,598)
Realized foreign exchange (loss) gain	**(203)**	275	(478)
Other (expense) income	**(250)**	232	(482)
Current income tax (expense) recovery	**(910)**	160	(1,070)
Share-based compensation - cash	**(2,239)**	(1,477)	(762)
Adjusted funds flow(2)	**$ 279,607**	$ 156,582	$ 123,025
Exploration and evaluation	**(3,570)**	(947)	(2,623)
Depletion and depreciation	**(140,791)**	(102,012)	(38,779)
Share-based compensation - non-cash	**(1,706)**	(1,504)	(202)
Non-cash financing and accretion	**(3,817)**	(3,047)	(770)
Non-cash other income	**1,282**	988	294
Unrealized financial derivatives loss	**(156,261)**	(85,984)	(70,277)
Unrealized foreign exchange gain	**14,548**	2,530	12,018
Gain on dispositions	**234**	3,706	(3,472)
Deferred income tax recovery (expense)	**67,332**	(5,664)	72,996
Net income (loss) for the period	**$ 56,858**	$ (35,352)	$ 92,210

(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 $279.6 million for Q1/2022 compared to $156.6 million for Q1/2021. The increase in adjusted funds flow for Q1/2022 was primarily due to higher operating netback which increased $188.4 million from Q1/2021 as a result of higher commodity prices that increased revenue, net of royalties. The increase in operating netback was partially offset by realized losses on financial derivatives of $84.4 million for Q1/2022 due to the increase in oil and natural gas benchmark prices relative to Q1/2021 when we recorded $20.8 million of losses on financial derivatives.

We reported net income of $56.9 million for Q1/2022 compared to a net loss of $35.4 million reported for Q1/2021.

OTHER COMPREHENSIVE INCOME (LOSS)

Other comprehensive income or loss is comprised of the foreign currency translation adjustment on U.S. net assets which is not recognized in net income or loss. The foreign currency translation loss of $28.1 million for Q1/2022 relates to the change in value of our U.S. net assets and is due to a strengthening of the Canadian dollar relative to the U.S. dollar at March 31, 2022 compared to December 31, 2021. The CAD/USD exchange rate was 1.2484 CAD/USD as at March 31, 2022 compared to 1.2656 CAD/USD at December 31, 2021.

CAPITAL EXPENDITURES

Capital expenditures for the three months ended March 31, 2022 and 2021 are summarized as follows.

	Three Months Ended March 31					
	2022			2021		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 107,000**	**$ 27,138**	**$ 134,138**	$ 39,034	$ 40,724	$ 79,758
Facilities	**7,764**	**386**	**8,150**	2,515	—	2,515
Land, seismic and other	**11,366**	**168**	**11,534**	954	361	1,315
Exploration and development expenditures	**$ 126,130**	**$ 27,692**	**$ 153,822**	$ 42,503	$ 41,085	$ 83,588
Property acquisitions	**$ 59**	**$ —**	**$ 59**	$ 25	$ —	$ 25
Proceeds from dispositions	**$ (27)**	**$ —**	**$ (27)**	$ (228)	$ —	$ (228)

Exploration and development expenditures were $153.8 million for Q1/2022 compared to $83.6 million for Q1/2021. Expenditures in Q1/2022 were higher compared to Q1/2021 as development increased throughout 2021 with the strengthening of commodity prices that continued into 2022.

In Canada, exploration and development expenditures were $126.1 million in Q1/2022 which is $83.6 million higher than $42.5 million in Q1/2021. Drilling and completion spending of $107.0 million in Q1/2022 reflects additional light and heavy oil development activity relative to Q1/2021 when we spent $39.0 million. Drilling and completion activity includes 6 (6.0 net) Clearwater wells brought on production during Q1/2022. We also invested $7.8 million on facilities and $11.4 million on land, seismic and workover expenditures during Q1/2022.

Total U.S. exploration and development expenditures were $27.7 million for Q1/2022 which is $13.4 million lower than Q1/2021 when exploration and development expenditures totaled $41.1 million. Exploration and development expenditures for Q1/2022 included costs associated with drilling 14 (2.3 net) wells along with 15 (4.7 net) wells that were brought on production compared to drilling 25 (7.5 net) wells along with 24 (7.0 net) wells brought on production during Q1/2021.

Our exploration and development expenditures for Q1/2022 are consistent with expectations. Due to inflationary pressures and our successful Clearwater development program we have increased our exploration and development expenditure guidance to $450 - $500 million for 2022.

CAPITAL RESOURCES AND LIQUIDITY

Our objective for capital management is to maintain a flexible capital structure and sufficient sources of liquidity to execute our capital programs, while meeting our short and long-term commitments. We strive to actively manage our capital structure in response to changes in economic conditions. At March 31, 2022, 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 our long-term plans. At March 31, 2022, net debt(1) of $1.28 billion was $134.0 million lower than $1.41 billion at December 31, 2021. The decrease in net debt during 2022 is primarily a result of the free cash flow(2) of $121.3 million 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 March 31, 2022, our net debt to adjusted funds flow ratio(1) was 1.5 compared to a ratio of 1.9 as at December 31, 2021. The decrease in the net debt to adjusted funds flow ratio relative to December 31, 2021 is attributed to higher adjusted funds flow for the trailing twelve months ended March 31, 2022 and lower net debt at March 31, 2022.

(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.

Credit Facilities

At March 31, 2022, the principal amount of borrowings and letters of credit outstanding was $441.7 million under our credit facilities. At March 31, 2022, the credit facilities consisted of a US$575.0 million revolving facility and a $300 million term loan set to mature on April 2, 2024 (the "Credit Facilities"). On April 1, 2022, we amended the Credit Facilities to eliminate the term loan and increase total revolving capacity to US$850.0 million while extending maturity to April 1, 2026.

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 secured overnight financing rates ("SOFR"), plus applicable margins.

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 2.4% for Q1/2022 compared to 2.1% for Q1/2021.

Financial Covenants

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at March 31, 2022.

Covenant Description	Position as at March 31, 2022	Covenant
Senior Secured Debt (1) to Bank EBITDA (2) (Maximum Ratio)	**0.5:1.0**	3.5:1.0
Interest Coverage (3) (Minimum Ratio)	**10.9:1.0**	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 March 31, 2022, the Company's Senior Secured Debt totaled $441.7 million which includes $426.9 million of principal amounts outstanding and $14.8 million of letters of credit.

(2) Bank EBITDA" is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expenses, income tax, non-recurring losses, certain specific unrealized and non-cash transactions 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 March 31, 2022 was $957.0 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 March 31, 2022 were $87.9 million.

Long-Term Notes

We have two series of long-term notes outstanding that total $873.9 million as at March 31, 2022. 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 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. At March 31, 2022, 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.

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 three months ended March 31, 2022, we issued 5.0 million common shares pursuant to our share-based compensation program. As at April 28, 2022, we had 569.2 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. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of March 31, 2022 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	**$ 257,683**	$ 257,683	$ —	$ —	$ —
Financial derivatives	**289,027**	276,823	12,204	—	—
Credit facilities - principal(1)(2)	**426,858**	—	426,858	—	—
Long-term notes - principal(2)	**873,880**	—	249,680	—	624,200
Interest on long-term notes(3)	**303,823**	68,662	125,627	109,235	299
Lease obligations(2)	**7,565**	3,015	3,871	563	116
Processing agreements	**7,654**	1,308	1,536	953	3,857
Transportation agreements	**74,892**	18,905	35,014	14,673	6,300
Total	**$ 2,241,382**	$ 626,396	$ 854,790	$ 125,424	$ 634,772

(1) As of March 31, 2022 the credit facilities were set to mature on April 2, 2024. On April 1, 2022 we extended the maturity of our credit facilities to April 1, 2026.

(2) Principal amount of instruments.

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

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

QUARTERLY FINANCIAL INFORMATION

	2022	2021				2020		
($ thousands, except per common share amounts)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Petroleum and natural gas sales	**673,825**	552,403	488,736	442,354	384,702	233,636	252,538	152,689
Net income (loss)	**56,858**	563,239	32,714	1,052,999	(35,352)	221,160	(23,444)	(138,463)
Per common share - basic	**0.10**	1.00	0.06	1.87	(0.06)	0.39	(0.04)	(0.25)
Per common share - diluted	**0.10**	0.98	0.06	1.85	(0.06)	0.39	(0.04)	(0.25)
Adjusted funds flow[(1)]	**279,607**	214,766	198,397	175,883	156,582	82,176	78,508	17,887
Per common share - basic	**0.49**	0.38	0.35	0.31	0.28	0.15	0.14	0.03
Per common share - diluted	**0.49**	0.37	0.35	0.31	0.28	0.15	0.14	0.03
Free cash flow[(2)]	**121,318**	137,133	101,215	112,486	70,495	1,794	59,939	5,939
Per common share - basic	**0.21**	0.24	0.18	0.20	0.13	—	0.11	0.01
Per common share - diluted	**0.21**	0.24	0.18	0.20	0.13	—	0.11	0.01
Cash flows from operating activities	**198,974**	240,567	178,961	171,876	120,980	51,017	93,688	25,824
Per common share - basic	**0.35**	0.43	0.32	0.30	0.22	0.09	0.17	0.05
Per common share - diluted	**0.35**	0.42	0.31	0.30	0.22	0.09	0.17	0.05
Exploration and development	**153,822**	73,995	94,235	61,485	83,588	77,809	15,902	9,852
Canada	**126,130**	59,821	75,499	30,387	42,503	45,030	3,882	2,929
U.S.	**27,692**	14,174	18,736	31,098	41,085	32,779	12,020	6,923
Property acquisitions	**59**	1,443	89	—	25	—	—	—
Proceeds from dispositions	**(27)**	(6,857)	(701)	(18)	(228)	(33)	(98)	(11)
Net debt[(1)]	**1,275,680**	1,409,717	1,564,658	1,629,629	1,758,894	1,847,601	1,906,079	1,994,953
Total assets	**4,836,189**	4,834,643	4,453,971	4,438,162	3,338,408	3,408,096	3,156,414	3,267,820
Common shares outstanding	**569,214**	564,213	564,213	564,182	564,111	561,227	561,163	560,545
Daily production								
Total production (boe/d)	**80,867**	80,789	79,872	81,162	78,780	70,475	77,814	72,508
Canada (boe/d)	**53,385**	50,362	48,124	47,205	52,039	45,321	49,164	37,691
U.S. (boe/d)	**27,482**	30,428	31,748	33,957	26,741	25,154	28,650	34,817
Benchmark prices								
WTI oil (US$/bbl)	**94.29**	77.19	70.56	66.07	57.84	42.66	40.93	27.85
WCS heavy ($/bbl)	**100.99**	78.82	71.81	67.03	57.46	43.46	42.40	22.70
Edmonton Light ($/bbl)	**115.66**	93.29	83.78	77.28	66.58	50.24	49.83	29.85
CAD/USD avg exchange rate	**1.2661**	1.2600	1.2601	1.2279	1.2663	1.3031	1.3316	1.3860
AECO gas ($/mcf)	**4.59**	4.94	3.54	2.85	2.93	2.77	2.18	1.91
NYMEX gas (US$/mmbtu)	**4.95**	5.83	4.01	2.83	2.69	2.66	1.98	1.72
Total sales, net of blending and other expense ($/boe)[(2)]	**86.89**	70.42	63.85	57.19	51.84	34.35	33.79	22.31
Royalties ($/boe)[(3)]	**(16.86)**	(13.47)	(12.32)	(11.04)	(9.44)	(5.83)	(5.59)	(4.42)
Operating expense ($/boe)[(3)]	**(13.85)**	(12.83)	(11.46)	(11.22)	(11.36)	(12.30)	(10.26)	(11.17)
Transportation expense ($/boe)[(3)]	**(1.27)**	(1.10)	(1.06)	(1.01)	(1.24)	(1.03)	(0.89)	(0.76)
Operating netback ($/boe)[(2)]	**54.91**	43.02	39.01	33.92	29.80	15.19	17.05	5.96
Financial derivatives gain (loss) ($/boe)[(3)]	**(11.59)**	(9.49)	(7.34)	(5.28)	(2.93)	2.64	(1.36)	2.06
Operating netback after financial derivatives ($/boe)[(2)]	**43.32**	33.53	31.67	28.64	26.87	17.83	15.69	8.02

(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 of 72,508 boe/d in Q2/2020 reflects our response to shut-in production as commodity prices collapsed due to the initial spread of COVID-19. Development activity was restarted as commodity prices stabilized during Q4/2020 and we maintained the pace of activity as commodity prices continued to improve throughout 2021. Strong well performance and our successful development programs have resulted in production of 80,867 boe/d for Q1/2022.

Decisions made by Saudi Arabia and Russia to increase production of crude oil as demand was decreasing due to the spread of COVID-19 resulted in a sharp decline in global crude oil prices with WTI averaging US$27.85/bbl in Q2/2020. Prices improved and were relatively stable through 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 strengthened to multi-year highs in Q1/2022 with WTI averaging US$94.29/bbl due to elevated uncertainty for the supply of oil following Russia's invasion of Ukraine in addition to limited production growth from large independent producers. The impact of increased commodity prices is reflected in our realized sales price of $86.89/boe for Q1/2022 which is our strongest realized pricing in 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 improved for Q1/2022 compared to the lows in 2020 due to strong price realizations which reflects the increase in benchmark commodity prices over the previous eight quarters.

Net debt can fluctuate on a quarterly basis depending on the timing of exploration and development expenditures, changes in our adjusted funds flow and the closing CAD/USD exchange rate which is used to translate our U.S. dollar denominated debt. Net debt(1) has decreased from $2.0 billion at Q2/2020 to $1.3 billion at Q1/2022 as free cash flow(2) of $610.3 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 1.3616 CAD/USD at Q2/2020 to 1.2484 CAD/USD at Q1/2022.

(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 AIF for the year ended December 31, 2021 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 the AIF for the year ended December 31, 2021, 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 March 31, 2022, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

There have been no changes in our critical accounting estimates in the three months ended March 31, 2022. Further information on our critical accounting policies and estimates can be found in the notes to the audited annual consolidated financial statements and MD&A for the year ended December 31, 2021.

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 a 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.

	Three Months Ended March 31	
($ thousands)	**2022**	2021
Petroleum and natural gas sales	**$ 673,825**	$ 384,702
Blending and other expense	**(41,440)**	(17,120)
Total sales, net of blending and other expense	**632,385**	367,582
Royalties	**(122,720)**	(66,950)
Operating expense	**(100,766)**	(80,548)
Transportation expense	**(9,215)**	(8,788)
Operating netback	**399,684**	211,296
Realized financial derivatives gain (loss)(1)	**(84,366)**	(20,768)
Operating netback after realized financial derivatives	**$ 315,318**	$ 190,528

(1) Realized financial derivatives gain or loss is a component of financial derivatives gain or loss; see Note 16 Financial Instruments and Risk Management in the Consolidated Financial Statements for the three months ended March 31, 2022 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.

	Three Months Ended March 31	
($ thousands)	**2022**	2021
Cash flows from operating activities	**$ 198,974**	$ 120,980
Change in non-cash working capital	**77,340**	34,185
Additions to exploration and evaluation assets	**(3,559)**	(216)
Additions to oil and gas properties	**(150,263)**	(83,372)
Payments on lease obligations	**(1,174)**	(1,082)
Free cash flow	**$ 121,318**	$ 70,495

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 of our credit facilities and long-term notes outstanding adjusted for unamortized debt issuance costs, trade and other payables, cash, and trade and other receivables. 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 twelve-month trailing adjusted funds flow.

The following table summarizes our calculation of net debt.

($ thousands)		March 31, 2022		December 31, 2021
Credit facilities	$	425,675	$	505,171
Unamortized debt issuance costs - Credit facilities [1]		1,183		1,343
Long-term notes		863,180		874,527
Unamortized debt issuance costs - Long-term notes [1]		10,700		11,393
Trade and other payables		257,683		190,692
Trade and other receivables		(282,741)		(173,409)
Net debt	$	1,275,680	$	1,409,717
Net debt to adjusted funds flow		1.5		1.9

(1) Unamortized debt issuance costs were obtained from Note 6 Credit Facilities and Note 7 Long-term Notes from the Consolidated Financial Statements for the three months ended March 31, 2022. 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 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.

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

	Three Months Ended March 31			
($ thousands)		2022		2021
Cash flow from operating activities	$	198,974	$	120,980
Change in non-cash working capital		77,340		34,185
Asset retirement obligations settled		3,293		1,417
Adjusted funds flow	$	279,607	$	156,582

INTERNAL CONTROL OVER FINANCIAL REPORTING

We are required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". This instrument requires us to disclose in our interim MD&A any weaknesses in or changes to our internal control over financial reporting during the period that may have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting. We confirm that no such weaknesses were identified in, or changes were made to, internal controls over financial reporting during the three months ended March 31, 2022.

FORWARD-LOOKING STATEMENTS

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

Specifically, this document contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; our 2022 guidance with respect to exploration and development expenditures, average daily production, royalty rate and operating, transportation, general and administrative and interest expenses; the existence, operation and strategy of our risk management program; the reassessment of our tax filings by the Canada Revenue Agency; our intention to defend the reassessments; our view of our tax filing position; and the manner in which we fund our planned capital expenditures and monitor and manage our capital resources and liquidity; we may issued debt or equity securities, sell assets or adjust capital spending.

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, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

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

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

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

	Notes	As at March 31, 2022	As at December 31, 2021
ASSETS			
Current assets			
Trade and other receivables		**$ 282,741**	$ 173,409
Financial derivatives	16	**6,181**	8,654
		288,922	182,063
Non-current assets			
Financial derivatives	16	**1,219**	—
Exploration and evaluation assets	4	**170,271**	172,824
Oil and gas properties	5	**4,360,624**	4,464,371
Other plant and equipment		**7,144**	7,121
Lease assets		**8,009**	8,264
		$ 4,836,189	$ 4,834,643
LIABILITIES			
Current liabilities			
Trade and other payables		**$ 257,683**	$ 190,692
Financial derivatives	16	**276,823**	134,020
Lease obligations		**2,885**	2,938
Asset retirement obligations	8	**11,015**	11,080
		548,406	338,730
Non-current liabilities			
Financial derivatives	16	**12,204**	—
Credit facilities	6	**425,675**	505,171
Long-term notes	7	**863,180**	874,527
Lease obligations		**4,445**	4,827
Asset retirement obligations	8	**641,674**	732,603
Deferred income tax liability	13	**98,791**	167,456
		2,594,375	2,623,314
SHAREHOLDERS' EQUITY			
Shareholders' capital	9	**5,745,022**	5,736,593
Contributed surplus		**6,836**	13,559
Accumulated other comprehensive income		**604,024**	632,103
Deficit		**(4,114,068)**	(4,170,926)
		2,241,814	2,211,329
		$ 4,836,189	$ 4,834,643

Subsequent event (note 6)

See accompanying notes to the condensed consolidated interim financial statements.

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

		Three Months Ended March 31	
	Notes	**2022**	2021
Revenue, net of royalties			
Petroleum and natural gas sales	12	**$ 673,825**	$ 384,702
Royalties		**(122,720)**	(66,950)
		551,105	317,752
Expenses			
Operating		**100,766**	80,548
Transportation		**9,215**	8,788
Blending and other		**41,440**	17,120
General and administrative		**11,682**	8,733
Exploration and evaluation	4	**3,570**	947
Depletion and depreciation		**140,791**	102,012
Share-based compensation	10	**3,945**	2,981
Financing and interest	14	**24,244**	27,450
Financial derivatives loss	16	**240,627**	106,752
Foreign exchange gain	15	**(14,345)**	(2,805)
Gain on dispositions		**(234)**	(3,706)
Other income		**(1,032)**	(1,220)
		560,669	347,600
Net loss before income taxes		**(9,564)**	(29,848)
Income tax expense (recovery)	13		
Current income tax expense (recovery)		**910**	(160)
Deferred income tax (recovery) expense		**(67,332)**	5,664
		(66,422)	5,504
Net income (loss)		**$ 56,858**	$ (35,352)
Other comprehensive income (loss)			
Foreign currency translation adjustment		**(28,079)**	(7,099)
Comprehensive income (loss)		**$ 28,779**	$ (42,451)
Net income (loss) per common share	11		
Basic		**$ 0.10**	$ (0.06)
Diluted		**$ 0.10**	$ (0.06)
Weighted average common shares (000's)	11		
Basic		**565,518**	562,085
Diluted		**569,705**	562,085

See accompanying notes to the condensed consolidated interim financial statements.

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

	Notes	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income	Deficit	**Total equity**
Balance at December 31, 2020		$ 5,729,418	$ 14,345	$ 618,976	$ (5,784,526)	**$ 578,213**
Vesting of share awards		6,975	(6,975)	—	—	**—**
Share-based compensation		—	1,504	—	—	**1,504**
Comprehensive loss		—	—	(7,099)	(35,352)	**(42,451)**
Balance at March 31, 2021		$ 5,736,393	$ 8,874	$ 611,877	$ (5,819,878)	**$ 537,266**
Balance at December 31, 2021		$ 5,736,593	$ 13,559	$ 632,103	$ (4,170,926)	**$ 2,211,329**
Vesting of share awards	9	8,429	(8,429)	—	—	**—**
Share-based compensation	10	—	1,706	—	—	**1,706**
Comprehensive income (loss)		—	—	(28,079)	56,858	**28,779**
Balance at March 31, 2022		$ 5,745,022	$ 6,836	$ 604,024	$ (4,114,068)	**$ 2,241,814**

See accompanying notes to the condensed consolidated interim financial statements.

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

		Three Months Ended March 31	
	Notes	**2022**	2021
CASH PROVIDED BY (USED IN):			
Operating activities			
Net income (loss)		**$ 56,858**	$ (35,352)
Adjustments for:			
Share-based compensation	10	**1,706**	1,504
Unrealized foreign exchange gain	15	**(14,548)**	(2,530)
Exploration and evaluation	4	**3,570**	947
Depletion and depreciation		**140,791**	102,012
Non-cash financing and accretion	14	**3,817**	3,047
Non-cash other income	8	**(1,282)**	(988)
Unrealized financial derivatives loss	16	**156,261**	85,984
Gain on dispositions		**(234)**	(3,706)
Deferred income tax (recovery) expense	13	**(67,332)**	5,664
Asset retirement obligations settled	8	**(3,293)**	(1,417)
Change in non-cash working capital		**(77,340)**	(34,185)
		198,974	120,980
Financing activities			
Decrease in credit facilities		**(78,142)**	(42,721)
Payments on lease obligations		**(1,174)**	(1,082)
		(79,316)	(43,803)
Investing activities			
Additions to exploration and evaluation assets	4	**(3,559)**	(216)
Additions to oil and gas properties	5	**(150,263)**	(83,372)
Additions to other plant and equipment		**(374)**	(91)
Property acquisitions		**(59)**	(25)
Proceeds from dispositions		**27**	228
Change in non-cash working capital		**34,570**	6,299
		(119,658)	(77,177)
Change in cash		**—**	—
Cash, beginning of period		**—**	—
Cash, end of period		**$ —**	$ —
Supplementary information			
Interest paid		**$ 30,348**	$ 30,837
Income taxes paid		**$ —**	$ —

See accompanying notes to the condensed consolidated interim financial statements.

1. REPORTING ENTITY

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

2. BASIS OF PRESENTATION

The condensed consolidated interim financial statements ("consolidated financial statements") have been prepared in accordance with International Accounting Standards 34, Interim Financial Reporting, under International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (the "IASB"). These condensed consolidated financial statements do not include all the necessary annual disclosures as prescribed by IFRS and should be read in conjunction with the annual consolidated financial statements as at and for the year ended December 31, 2021.

The consolidated financial statements were approved by the Board of Directors of Baytex on April 28, 2022.

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

The audited consolidated financial statements of the Company as at and for the year ended December 31, 2021 are available through its filings on SEDAR at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov.

Significant Accounting Policies

The accounting policies, critical accounting judgments and significant estimates used in preparation of the 2021 annual financial statements have been applied in the preparation of these consolidated financial statements.

Current Environment and Estimation Uncertainty

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

During the three months ended March 31, 2022, demand for oil and natural gas improved as the global economy continued to recover from the COVID-19 pandemic. Energy prices strengthened to multi-year highs due to elevated uncertainty of global oil and natural gas supply after Russia's invasion of Ukraine in addition to limited production growth reflecting oil and gas producers' capital discipline. While we have benefited from these improvements in crude oil prices, there is uncertainty related to COVID-19 and geopolitical events that have been considered in our estimates as at and for the period ended March 31, 2022.

3. SEGMENTED FINANCIAL INFORMATION

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

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

	Canada		**U.S.**		**Corporate**		**Consolidated**	
Three Months Ended March 31	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 453,704**	$ 239,423	**$ 220,121**	$ 145,279	**$ —**	$ —	**$ 673,825**	$ 384,702
Royalties	**(57,676)**	(24,664)	**(65,044)**	(42,286)	**—**	—	**(122,720)**	(66,950)
	396,028	214,759	**155,077**	102,993	**—**	—	**551,105**	317,752
Expenses								
Operating	**78,540**	61,361	**22,226**	19,187	**—**	—	**100,766**	80,548
Transportation	**9,215**	8,788	**—**	—	**—**	—	**9,215**	8,788
Blending and other	**41,440**	17,120	**—**	—	**—**	—	**41,440**	17,120
General and administrative	**—**	—	**—**	—	**11,682**	8,733	**11,682**	8,733
Exploration and evaluation	**3,570**	947	**—**	—	**—**	—	**3,570**	947
Depletion and depreciation	**101,082**	70,474	**38,364**	30,265	**1,345**	1,273	**140,791**	102,012
Share-based compensation	**—**	—	**—**	—	**3,945**	2,981	**3,945**	2,981
Financing and interest	**—**	—	**—**	—	**24,244**	27,450	**24,244**	27,450
Financial derivatives loss	**—**	—	**—**	—	**240,627**	106,752	**240,627**	106,752
Foreign exchange gain	**—**	—	**—**	—	**(14,345)**	(2,805)	**(14,345)**	(2,805)
Gain on dispositions	**(234)**	(3,706)		—	**—**	—	**(234)**	(3,706)
Other (income) expense	**(1,282)**	(988)	**—**	—	**250**	(232)	**(1,032)**	(1,220)
	232,331	153,996	**60,590**	49,452	**267,748**	144,152	**560,669**	347,600
Net income (loss) before income taxes	**163,697**	60,763	**94,487**	53,541	**(267,748)**	(144,152)	**(9,564)**	(29,848)
Income tax expense (recovery)								
Current income tax (recovery) expense	**—**	(296)	**910**	136	**—**	—	**910**	(160)
Deferred income tax expense (recovery)	**71,404**	8,420	**15,449**	5,664	**(154,185)**	(8,420)	**(67,332)**	5,664
	71,404	8,124	**16,359**	5,800	**(154,185)**	(8,420)	**(66,422)**	5,504
Net income (loss)	**$ 92,293**	$ 52,639	**$ 78,128**	$ 47,741	**$ (113,563)**	$ (135,732)	**$ 56,858**	$ (35,352)
Additions to exploration and evaluation assets	**3,559**	216	**—**	—	**—**	—	**3,559**	216
Additions to oil and gas properties	**122,571**	42,287	**27,692**	41,085	**—**	—	**150,263**	83,372
Property acquisitions	**59**	25	**—**	—	**—**	—	**59**	25
Proceeds from dispositions	**(27)**	(228)	**—**	—	**—**	—	**(27)**	(228)

	March 31, 2022	December 31, 2021
Canadian assets	**$ 2,695,372**	$ 2,658,281
U.S. assets	**2,118,264**	2,152,323
Corporate assets	**22,553**	24,039
Total consolidated assets	**$ 4,836,189**	$ 4,834,643

4. EXPLORATION AND EVALUATION ASSETS

	March 31, 2022	December 31, 2021
Balance, beginning of period	**$ 172,824**	$ 191,865
Capital expenditures	**3,559**	3,298
Property acquisitions	**—**	1,100
Divestitures	**(8)**	(166)
Property swaps	**—**	408
Exploration and evaluation expense	**(3,570)**	(15,212)
Transfer to oil and gas properties (note 5)	**(1,387)**	(7,727)
Foreign currency translation	**(1,147)**	(742)
Balance, end of period	**$ 170,271**	$ 172,824

At March 31, 2022 and December 31, 2021, there were no indicators of impairment or impairment reversal for exploration and evaluation assets in any of the Company's cash generating units ("CGU").

5. OIL AND GAS PROPERTIES

	Cost	Accumulated depletion	Net book value
Balance, December 31, 2020	**$ 11,423,676**	**$ (8,346,128)**	**$ 3,077,548**
Capital expenditures	310,005	—	310,005
Property acquisitions	274	—	274
Transfers from exploration and evaluation assets (note 4)	7,727	—	7,727
Change in asset retirement obligations (note 8)	(12,222)	—	(12,222)
Divestitures	(37,835)	32,844	(4,991)
Property swaps	(26,131)	25,900	(231)
Impairment reversal	—	1,542,414	1,542,414
Foreign currency translation	(31,977)	34,765	2,788
Depletion	—	(458,941)	(458,941)
Balance, December 31, 2021	**$ 11,633,517**	**$ (7,169,146)**	**$ 4,464,371**
Capital expenditures	150,263	—	150,263
Property acquisitions	15	—	15
Transfers from exploration and evaluation assets (note 4)	1,387	—	1,387
Change in asset retirement obligations (note 8)	(88,711)	—	(88,711)
Foreign currency translation	(57,373)	30,118	(27,255)
Depletion	—	(139,446)	(139,446)
Balance, March 31, 2022	**$ 11,639,098**	**$ (7,278,474)**	**$ 4,360,624**

At March 31, 2022, there were no indicators of impairment or impairment reversal for oil and gas properties in any of the Company's CGUs.

2021 Impairment Reversals

At December 31, 2021, we identified indicators of impairment reversal for oil and gas properties in five CGUs due to the increase in forecasted commodity prices in addition to changes in proved plus probable reserves. The recoverable amount for three CGUs exceeded their carrying amounts which resulted in an impairment reversal of $416 million recorded at December 31, 2021. The recoverable amount for each CGU was based on its fair value less costs of disposal ("FVLCD") which was estimated using a discounted cash flow model of proved plus probable cash flows from an independent reserve report prepared as at December 31, 2021. The after-tax discount rates applied to the cash flows were between 12% and 19%.

At June 30, 2021, we identified indicators of impairment reversal for oil and gas properties in each of our six CGUs due to the increase in forecasted commodity prices. The recoverable amount for each of our six CGUs exceeded their carrying amounts which resulted in an impairment reversal of $1.1 billion recorded at June 30, 2021. The recoverable amount for each CGU was based on its FVLCD which was estimated using a discounted cash flow model of proved plus probable cash flows from an independent reserve report prepared as at December 31, 2020 and was adjusted by management for operations between December 31, 2020 and June 30, 2021. The after-tax discount rates applied to the cash flows were between 10% and 16%.

6. CREDIT FACILITIES

		March 31, 2022		December 31, 2021
Credit facilities - U.S. dollar denominated[1]	**$**	**115,579**	$	156,332
Credit facilities - Canadian dollar denominated		**311,279**		350,182
Credit facilities - principal		**426,858**		506,514
Unamortized debt issuance costs		**(1,183)**		(1,343)
Credit facilities	**$**	**425,675**	$	505,171

(1) U.S. dollar denominated credit facilities balance was US$92.6 million as at March 31, 2022 (December 31, 2021 - US$123.5 million).

(2) The decrease in the principal amount of the credit facilities outstanding from December 31, 2021 to March 31, 2022 is the result of net repayments of $78.1 million and a decrease in the reported amount of U.S. denominated debt of $1.5 million due to foreign exchange.

At March 31, 2022, Baytex had US$575 million of revolving credit facilities (the "Revolving Facilities") and a $300 million non-revolving secured term loan (the "Term Loan") (collectively the "Credit Facilities"). On April 1, 2022, Baytex amended the credit facilities to increase total capacity to a US$850 million revolving facility that matures on April 1, 2026. The amended secured Revolving Facilities are comprised of a US$50 million operating loan and a US$600 million syndicated revolving loan for Baytex and a US$10 million operating loan and a US$190 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc. There was no change to the financial covenants as a result of the amendment.

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 secured overnight financing rates ("SOFR"), plus applicable margins.

The weighted average interest rate on the Credit Facilities was 2.4% for the three months ended March 31, 2022 (2.1% for three months ended March 31, 2021).

At March 31, 2022, Baytex had $14.8 million of outstanding letters of credit (December 31, 2021 - $15.0 million) under the Credit Facilities.

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at March 31, 2022.

Covenant Description	**Position as at March 31, 2022**	**Covenant**
Senior Secured Debt [1] to Bank EBITDA [2] (Maximum Ratio)	**0.5:1.0**	**3.5:1.0**
Interest Coverage [3] (Minimum Ratio)	**10.9:1.0**	**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 March 31, 2022, the Company's Senior Secured Debt totaled $441.7 million which included $426.9 million of principal amounts outstanding and $14.8 million of letters of credit.

(2) "Bank EBITDA" is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expenses, income tax, non-recurring losses, certain specific unrealized and non-cash transactions 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 March 31, 2022 was $957.0 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 expense for the twelve months ended March 31, 2022 was $87.9 million.

7. LONG-TERM NOTES

		March 31, 2022		December 31, 2021
5.625% notes (US$200,000 – principal) due June 1, 2024	**$**	**249,680**	$	253,120
8.75% notes (US$500,000 – principal) due April 1, 2027		**624,200**		632,800
Total long-term notes - principal [(1)]		**873,880**		885,920
Unamortized debt issuance costs		**(10,700)**		(11,393)
Total long-term notes - net of unamortized debt issuance costs	**$**	**863,180**	$	874,527

(1) The decrease in the principal amount of long-term notes outstanding from December 31, 2021 to March 31, 2022 is the result of changes in the reported amount of U.S. denominated debt of $12.0 million.

The long-term notes do not contain any significant financial maintenance covenants but do contain a debt incurrence covenant that restricts the Company's ability to raise additional debt beyond the existing Credit Facilities and long-term notes.

8. ASSET RETIREMENT OBLIGATIONS

		March 31, 2022		December 31, 2021
Balance, beginning of period	**$**	**743,683**	$	760,383
Liabilities incurred		**7,893**		14,845
Liabilities settled		**(3,293)**		(6,662)
Liabilities acquired from property acquisitions		**—**		249
Liabilities divested		**(259)**		(3,161)
Property swaps		**—**		(4,113)
Accretion (note 14)		**3,122**		12,381
Government grants [(1)]		**(1,282)**		(2,857)
Change in estimate		**531**		(9,686)
Changes in discount rates and inflation rates [(2)]		**(97,135)**		(17,381)
Foreign currency translation		**(571)**		(315)
Balance, end of period	**$**	**652,689**	$	743,683
Less current portion of asset retirement obligations		**11,015**		11,080
Non-current portion of asset retirement obligations	**$**	**641,674**	$	732,603

(1) During the three months ended March 31, 2022, Baytex recognized $1.3 million of non-cash other income and a reduction in asset retirement obligations related to government grants provided by the Government of Alberta and the Government of Saskatchewan ($2.9 million for the year ended December 31, 2021).

(2) The discount and inflation rates at March 31, 2022 were 2.4% and 1.8%, respectively, compared to 1.7% and 1.8% at December 31, 2021.

9. SHAREHOLDERS' CAPITAL

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10.0 million preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. At March 31, 2022, no preferred shares have been issued by the Company and all common shares issued were fully paid.

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

	Number of Common Shares (000s)		Amount
Balance, December 31, 2020	**561,227**	**$**	**5,729,418**
Vesting of share awards	2,986		7,175
Balance, December 31, 2021	**564,213**	**$**	**5,736,593**
Vesting of share awards	5,001		8,429
Balance, March 31, 2022	**569,214**	**$**	**5,745,022**

10. SHARE-BASED COMPENSATION PLAN

For the three months ended March 31, 2022 the Company recorded total compensation expense related to the share awards of $3.9 million ($3.0 million for the three months ended March 31, 2021) which includes $2.2 million of cash compensation expense related to the incentive award plan, deferred share unit plan and the associated equity total return swaps ($1.5 million for the three months ended March 31, 2021).

Share Award Incentive Plan

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

The weighted average fair value of share awards granted during the three months ended March 31, 2022 was $5.68 per restricted and performance award ($1.29 for the three months ended March 31, 2021).

The number of share awards outstanding is detailed below:

(000s)	Number of restricted awards	Number of performance awards	Total number of share awards
Balance, December 31, 2020	**4,122**	**4,088**	**8,210**
Granted	—	4,067	4,067
Added by performance factor	—	669	669
Vested and converted to common shares	(1,861)	(1,152)	(3,013)
Forfeited	(168)	(291)	(459)
Balance, December 31, 2021	**2,093**	**7,381**	**9,474**
Granted	—	1,104	1,104
Vested and converted to common shares	(1,359)	(3,614)	(4,973)
Forfeited	(22)	(25)	(47)
Balance, March 31, 2022	**712**	**4,846**	**5,558**

Incentive Award Plan

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

During the three months ended March 31, 2022, Baytex granted 1.3 million awards under the Incentive Award plan at a fair value of $5.68 per award (4.9 million awards at $1.29 per award for the three months ended March 31, 2021). At March 31, 2022 there were 5.4 million awards outstanding under the Incentive Award plan (6.4 million awards outstanding at December 31, 2021).

Deferred Share Unit Plan

Baytex has a deferred share unit plan (the "DSU" plan) whereby each Director of Baytex is entitled to receive a cash payment equal to the value of one Baytex common share on the date on which they cease to be a member of the Board. The awards vest immediately upon being granted and are expensed in full on the grant date. The units are recognized at fair value at each period end and are included in trade and other payables.

During the three months ended March 31, 2022, Baytex granted 0.2 million awards under the DSU plan at a fair value of $5.68 per award (0.9 million awards at $1.29 per award for the three months ended March 31, 2021). At March 31, 2022, there were 1.0 million awards outstanding under the DSU plan.

The Company uses equity total return swaps on the equivalent number of Baytex common shares in order to fix a portion of the aggregate cost of the Incentive Award plan and the DSU plan at the fair value determined on the grant date. The carrying value of the financial derivatives includes the fair value of the equity total return swap which was an asset of $6.2 million on March 31, 2022 (December 31, 2021 - asset of $6.5 million). At March 31, 2022, an asset of $10.6 million associated with the equity return swap is included in accounts payable as it relates to the settlement of cash compensation payable (December 31, 2021 - an asset of $10.7 million).

11. NET INCOME (LOSS) PER SHARE

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

	Three Months Ended March 31					
	2022			2021		
	Net income	**Weighted average common shares (000s)**	**Net income per share**	Net loss	Weighted average common shares (000s)	Net loss per share
Net income (loss) - basic	**$ 56,858**	**565,518**	**$ 0.10**	$ (35,352)	562,085	$ (0.06)
Dilutive effect of share awards	**—**	**4,187**	**—**	—	—	—
Net income (loss) - diluted	**$ 56,858**	**569,705**	**$ 0.10**	$ (35,352)	562,085	$ (0.06)

For the three months ended March 31, 2022 no share awards were excluded from the calculation of diluted loss per share as their effect was dilutive. For the three months ended March 31, 2021, all share awards were excluded from the calculation of diluted loss per share as their effect was anti-dilutive given the Company recorded a net loss.

12. PETROLEUM AND NATURAL GAS SALES

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

	Three Months Ended March 31					
	2022			2021		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 180,156**	**$ 180,820**	**$ 360,976**	$ 111,546	$ 105,596	$ 217,142
Heavy oil	**244,439**	**—**	**244,439**	109,038	—	109,038
NGL	**7,483**	**22,007**	**29,490**	4,364	13,142	17,506
Natural gas sales	**21,626**	**17,294**	**38,920**	14,475	26,541	41,016
Total petroleum and natural gas sales	**$ 453,704**	**$ 220,121**	**$ 673,825**	$ 239,423	$ 145,279	$ 384,702

Included in accounts receivable at March 31, 2022 is $265.4 million of accrued production revenue related to delivered volumes (December 31, 2021 - $154.0 million).

13. INCOME TAXES

The provision for income taxes has been computed as follows:

	Three Months Ended March 31	
	2022	2021
Net loss before income taxes	**$ (9,564)**	$ (29,848)
Expected income taxes at the statutory rate of 25.12% (2021 – 24.89%)	**(2,402)**	(7,429)
(Increase) decrease in income tax recovery resulting from:		
Effect of foreign exchange	**(1,848)**	(339)
Effect of rate adjustments for foreign jurisdictions	**(3,572)**	(871)
Effect of change in deferred tax benefit not recognized	**9,292**	13,937
Effect of internal debt restructuring	**(67,301)**	—
Adjustments, assessments and other	**(591)**	206
Income tax (recovery) expense	**$ (66,422)**	$ 5,504

At March 31, 2022, a deferred tax asset of $154.9 million remains unrecognized due to uncertainty surrounding future commodity prices and future capital gains (December 31, 2021 - $145.6 million).

As disclosed in the 2021 annual financial statements, in June 2016, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency (the “CRA”) that denied $591.0 million of non-capital loss deductions that relate to the calculation of income taxes for the years 2011 through 2015. In September 2016, Baytex filed notices of objection with the CRA appealing each reassessment received. There has been no change in the status of these reassessments since an Appeals Officer was assigned to the Company's file in July 2018. Baytex remains confident that the original tax filings are correct and intends to defend those tax filings through the appeals process.

14. FINANCING AND INTEREST

	Three Months Ended March 31	
	2022	2021
Interest on credit facilities	**$ 3,039**	$ 3,336
Interest on long-term notes	**17,344**	21,007
Interest on lease obligations	**44**	60
Cash Interest	**$ 20,427**	$ 24,403
Amortization of debt issue costs	**695**	749
Accretion on asset retirement obligations (note 8)	**3,122**	2,298
Financing and interest	**$ 24,244**	$ 27,450

15. FOREIGN EXCHANGE

	Three Months Ended March 31	
	2022	2021
Unrealized foreign exchange (gain) loss - intercompany notes (1)	**$ (2,674)**	$ 13,741
Unrealized foreign exchange gain - long-term notes & credit facilities	**(11,874)**	(16,271)
Realized foreign exchange loss (gain)	**203**	(275)
Foreign exchange gain	**$ (14,345)**	$ (2,805)

(1) Baytex had a series of intercompany notes totaling US$601.0 million outstanding at December 31, 2021 that were issued from a Canadian functional currency subsidiary to a U.S. functional currency subsidiary. These notes are eliminated upon consolidation within the Statement of Financial Position and are revalued at the relevant foreign exchange rate at each period end. Foreign exchange gains or losses incurred within the Canadian functional currency subsidiary are recognized in unrealized foreign exchange gain or loss whereas those within the U.S. functional currency subsidiary are recognized in other comprehensive income. In January 2022 the intercompany notes were transferred from the Canadian functional currency subsidiary to another U.S. functional currency subsidiary. As a result, foreign exchange gains and losses incurred on these notes after the transfer are recognized in other comprehensive income.

16. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

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

	March 31, 2022		December 31, 2021		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL					
Financial derivatives	**$ 7,400**	**$ 7,400**	$ 8,654	$ 8,654	Level 2
Total	**$ 7,400**	**$ 7,400**	$ 8,654	$ 8,654	
Amortized cost					
Trade and other receivables	**$ 282,741**	**$ 282,741**	$ 173,409	$ 173,409	—
Total	**$ 282,741**	**$ 282,741**	$ 173,409	$ 173,409	
Financial Liabilities					
FVTPL					
Financial derivatives	**$ (289,027)**	**$ (289,027)**	$ (134,020)	$ (134,020)	Level 2
Total	**$ (289,027)**	**$ (289,027)**	$ (134,020)	$ (134,020)	
Amortized cost					
Trade and other payables	**$ (257,683)**	**$ (257,683)**	$ (190,692)	$ (190,692)	—
Credit facilities	**(425,675)**	**(426,858)**	(505,171)	(506,514)	—
Long-term notes	**(863,180)**	**(924,844)**	(874,527)	(917,889)	Level 1
Total	**$ (1,546,538)**	**$ (1,609,385)**	$ (1,570,390)	$ (1,615,095)	

There were no transfers between Level 1 and Level 2 during the three months ended March 31, 2022 and 2021.

Foreign Currency Risk

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

	Assets		Liabilities	
	March 31, 2022	December 31, 2021	**March 31, 2022**	December 31, 2021
U.S. dollar denominated	**US$355**	US$602,503	**US$975,053**	US$829,934

Commodity Price Risk

Financial Derivative Contracts

Baytex had the following financial derivative contracts outstanding as of April 28, 2022:

	Remaining Period	Volume	Price/Unit[1]	Index
Oil				
Basis Swap	Apr 2022 to Dec 2022	12,000 bbl/d	WTI less US$12.40/bbl	WCS
Basis Swap	Apr 2022 to Jun 2022	1,000 bbl/d	WTI less US$3.00/bbl	MSW
Basis Swap	Apr 2022 to Dec 2022	6,000 bbl/d	WTI less US$3.91/bbl	MSW
Basis Swap	Jul 2022 to Dec 2022	750 bbl/d	WTI less US$2.30/bbl	MSW
Fixed Sell	Apr 2022 to Dec 2022	10,000 bbl/d	US$53.50/bbl	WTI
3-way option[2]	Apr 2022 to Dec 2022	1,500 bbl/d	US$40.00/US$50.00/US$58.10	WTI
3-way option[2]	Apr 2022 to Dec 2022	2,000 bbl/d	US$46.00/US$56.00/US$66.72	WTI
3-way option[2]	Apr 2022 to Dec 2022	2,500 bbl/d	US$47.00/US$57.00/US$67.00	WTI
3-way option[2]	Apr 2022 to Dec 2022	2,500 bbl/d	US$50.00/US$60.00/US$70.00	WTI
3-way option[2]	Apr 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]	Jan 2023 to Dec 2023	2,500 bbl/d	US$60.00/US$75.00/US$91.54	WTI
3-way option[2]	Jan 2023 to Dec 2023	2,500 bbl/d	US$65.00/US$85.00/US$100.00	WTI
3-way option[2]	Jan 2023 to Dec 2023	2,500 bbl/d	US$65.00/US$85.00/US$106.50	WTI
Natural Gas				
Fixed Sell	Apr 2022 to Dec 2022	5,000 GJ/d	$2.53/GJ	AECO 7A
Fixed Sell	Apr 2022 to Dec 2022	14,250 GJ/d	$2.84/GJ	AECO 5A
Fixed Sell	Apr 2022 to Dec 2022	1,000 mmbtu/d	US$2.94/mmbtu	NYMEX
3-way option[2]	Apr 2022 to Dec 2022	2,500 mmbtu/d	US$2.25/US$2.75/US$3.06	NYMEX
3-way option[2]	Apr 2022 to Dec 2022	1,500 mmbtu/d	US$2.60/US$2.91/US$3.56	NYMEX
3-way option[2]	Apr 2022 to Dec 2022	2,500 mmbtu/d	US$2.60/US$3.00/US$3.83	NYMEX
3-way option[2]	Apr 2022 to Dec 2022	2,500 mmbtu/d	US$2.65/US$2.90/US$3.40	NYMEX
3-way option[2]	Apr 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.

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

	Three Months Ended March 31	
	2022	2021
Realized financial derivatives loss	**$ 84,366**	$ 20,768
Unrealized financial derivatives loss	**156,261**	85,984
Financial derivatives loss	**$ 240,627**	$ 106,752

17. CAPITAL MANAGEMENT

The Company's capital management objective is to maintain financial flexibility and sufficient sources of liquidity to execute its capital programs, while meeting short and long-term commitments. Baytex strives to actively manage its capital structure in response to changes in economic conditions. At March 31, 2022, the Company's 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 its capital structure and liquidity, Baytex may from time to time issue equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

The capital intensive nature of Baytex's operations requires the maintenance of adequate sources of liquidity to fund ongoing exploration and development. Baytex's capital resources consist primarily of Adjusted Funds Flow, available Credit Facilities and proceeds received from the divestiture of oil and gas properties. The following capital management measures and ratios are used to monitor current and projected sources of liquidity.

Net Debt

The Company uses net debt to monitor it's current financial position and to evaluate existing sources of liquidity. Baytex also uses net debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations.

The following table reconciles Net Debt to amounts disclosed in the primary financial statements.

	March 31, 2022	December 31, 2021
Credit facilities	$ 425,675	$ 505,171
Unamortized debt issuance costs - Credit Facilities (note 6)	1,183	1,343
Long-term notes	863,180	874,527
Unamortized debt issuance costs - Long-term notes (note 7)	10,700	11,393
Trade and other payables	257,683	190,692
Trade and other receivables	(282,741)	(173,409)
Net Debt	$ 1,275,680	$ 1,409,717
Net Debt to Adjusted Funds Flow	1.5	1.9

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. Baytex also uses 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.

Adjusted Funds Flow is reconciled to amounts disclosed in the primary financial statements in the following table.

	Three Months Ended March 31	
	2022	2021
Cash flows from operating activities	$ 198,974	$ 120,980
Change in non-cash working capital	77,340	34,185
Asset retirement obligations settled	3,293	1,417
Adjusted Funds Flow	$ 279,607	$ 156,582

ABBREVIATIONS

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

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

CORPORATE INFORMATION

BOARD OF DIRECTORS

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Chairman of the Board

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Director

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Director

Don G. Hrap [1,3]
Director

Jennifer A. Maki [1,2]
Director

Gregory K. Melchin [1,4]
Director

David L. Pearce [2,3]
Director

Steve D.L. Reynish [3,4]
Director

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

OFFICERS

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President and
Chief Executive Officer

Rodney D. Gray
Executive Vice President
and Chief Financial Officer

Chad E. Lundberg
Chief Operating and
Sustainability Officer

Kendall D. Arthur
Vice President, Heavy Oil

Brian G. Ector
Vice President, Capital Markets

Nicole M. Frechette
Vice President, Light Oil

Chad L. Kalmakoff
Vice President, Finance

Scott Lovett
Vice President,
Corporate Development

James R. Maclean
Vice President, General Counsel
and Corporate Secretary

AUDITORS

KPMG LLP

RESERVES ENGINEERS

McDaniel & Associates Consultants Ltd.

TRANSFER AGENT

Odyssey Trust Company

EXCHANGE LISTINGS

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