



20 ANNUAL REPORT 21

TAKING THE LEAD

CREATING ENERGY
CREATING VALUE



OUR HIGHLIGHTS



24%
reduction
in net debt



80,156 boe/d
for the full-year 2021



Clearwater appraisal program
delivers
exciting results



\$421 million
free cash flow⁽¹⁾



52%
reduction in GHG emissions intensity,
relative to our 2018 baseline

1) Non-GAAP 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. See "Specified Financial Measures" in the 2021 Annual MD&A for information related to this non-GAAP financial measure, which information is incorporated by reference into this document.

OUR OPERATING AREAS

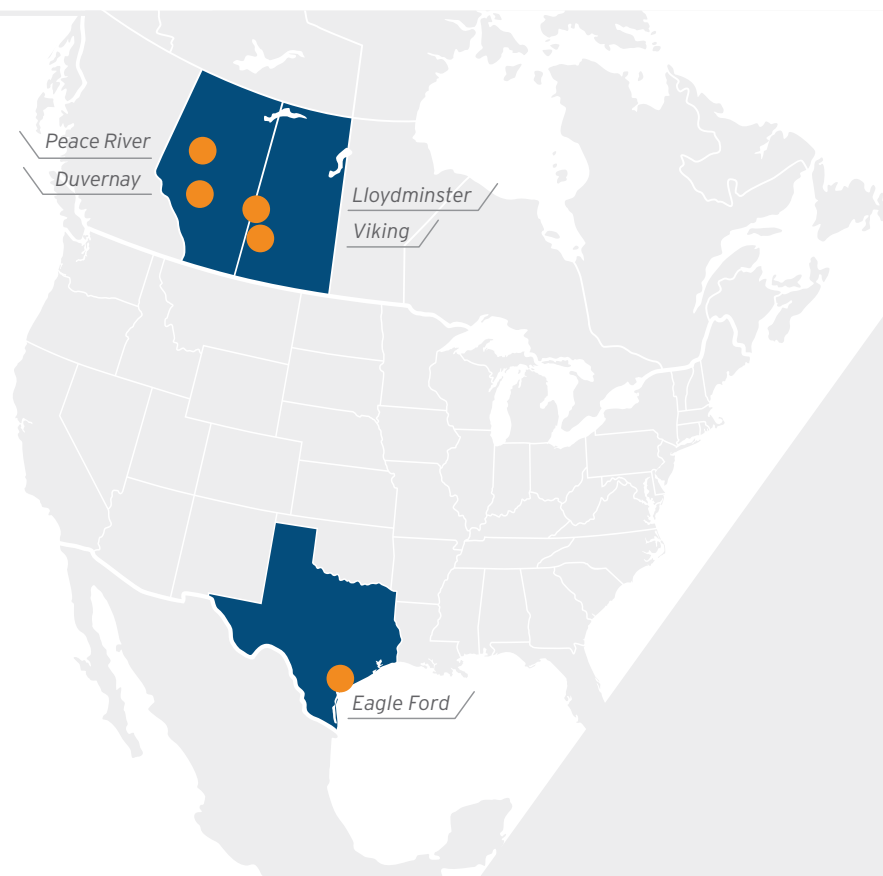


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SUMMARY

	Twelve Months Ended	
	December 31, 2021	December 31, 2020
FINANCIAL		
(thousands of Canadian dollars, except per common share amounts)		
Petroleum and natural gas sales	\$ 1,868,195	\$ 975,477
Adjusted funds flow ⁽¹⁾	745,628	311,506
Per share – basic	1.32	0.56
Per share – diluted	1.30	0.56
Free cash flow ⁽²⁾	421,329	18,073
Per share – basic	0.75	0.03
Per share – diluted	0.74	0.03
Cash flows from operating activities	712,384	353,096
Per share – basic	1.26	0.63
Per share – diluted	1.25	0.63
Net income (loss)	1,613,600	(2,438,964)
Per share – basic	2.86	(4.35)
Per share – diluted	2.82	(4.35)
Capital Expenditures		
Exploration and development expenditures	\$ 313,303	\$ 280,340
Acquisitions and divestitures	(6,247)	(182)
Total oil and natural gas capital expenditures	\$ 307,056	\$ 280,158
Net Debt		
Credit facilities	\$ 506,514	\$ 651,173
Long-term notes	885,920	1,147,950
Long-term debt	1,392,434	1,799,123
Working capital deficiency	17,283	48,478
Net debt ⁽¹⁾	\$ 1,409,717	\$ 1,847,601
Shares Outstanding - basic (thousands)		
Weighted average	563,674	560,657
End of period	564,213	561,227

Twelve Months Ended

	December 31, 2021	December 31, 2020
OPERATING		
Daily Production		
Light oil and condensate (bbl/d)	35,789	37,056
Heavy oil (bbl/d)	22,188	21,142
NGL (bbl/d)	7,244	7,340
Total liquids (bbl/d)	65,221	65,538
Natural gas (mcf/d)	89,606	85,464
Oil equivalent (boe/d @ 6:1) ⁽³⁾	80,156	79,781
Netback (thousands of Canadian dollars)		
Total sales, net of blending and other expense ⁽²⁾	\$ 1,782,506	\$ 927,096
Royalties	(339,156)	(163,735)
Operating expense	(343,002)	(331,345)
Transportation expense	(32,261)	(28,437)
Operating netback ⁽²⁾	\$ 1,068,087	\$ 403,579
General and administrative	(40,804)	(34,268)
Cash financing and interest	(92,069)	(106,534)
Realized financial derivatives (loss) gain	(184,241)	47,836
Other ⁽⁴⁾	(5,345)	893
Adjusted funds flow ⁽¹⁾	\$ 745,628	\$ 311,506
Netback per boe ⁽⁵⁾		
Total sales, net of blending and other expense ⁽²⁾	\$ 60.93	\$ 31.75
Royalties	(11.59)	(5.61)
Operating expense	(11.72)	(11.35)
Transportation expense	(1.10)	(0.97)
Operating netback ⁽²⁾	\$ 36.52	\$ 13.82
General and administrative	(1.39)	(1.17)
Cash financing and interest	(3.15)	(3.65)
Realized financial derivatives (loss) gain	(6.30)	1.64
Other ⁽⁴⁾	(0.19)	0.03
Adjusted funds flow ⁽¹⁾	\$ 25.49	\$ 10.67

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 share-based compensation. Refer to the 2021 MD&A for further information on these amounts.
- (5) Calculated as royalties, operating or transportation expense divided by barrels of oil equivalent production volume for the applicable period.

Advisory Regarding Forward-Looking Statements

In the interest of providing Baytex's shareholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements in this report are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "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 report speak only as of the date thereof and are expressly qualified by this cautionary statement.

Specifically, this document contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; that we continue to advance our Clearwater play; that our 5-year plan targets capital spending at ~50% of adjusted funds flow at a US\$65 WTI price, generates \$2.1 billion of cumulative free cash flow, and grows production to 90,000 boe/d (2% to 4% annual production growth) and at US\$75 and \$85 WTI generates \$2.8 billion and \$3.4 billion of cumulative free cash flow; inventory enhancement continues to be a priority; our Clearwater play holds the potential for >200 locations and 18 Clearwater wells are planned for 2022; oil and gas will be instrumental for in the energy transition; our GHG emissions commitments and targets; our 2040 abandonment and reclamation commitment; we expect to benefit from our diversified oil weighted portfolio and commitment to allocate capital effectively; for 2022, our capital budget, expected average daily production and expected free cash flow; that we intend to allocate ~25% of our free cash flow to share buybacks commencing Q2/2022; de-leveraging remains a priority; our long-term net debt target of \$800 million and that we expect to hit that net debt target mid-2023 at which point we will consider further enhanced shareholder returns. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

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

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices and price differentials (including the impacts of Covid-19); restrictions or costs imposed by climate change initiatives and the physical risks of climate change; risks associated with our ability to develop our properties and add reserves; the impact of an energy transition on demand for petroleum productions; changes in income tax or other laws or government incentive programs; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; the availability and cost of capital or borrowing; risks associated with a third-party operating our Eagle Ford properties; risks associated with large projects; costs to develop and operate our properties; public perception and its influence on the regulatory regime; current or future control, legislation or regulations; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; regulations regarding the disposal of fluids; risks associated with our hedging activities; variations in interest rates and foreign exchange rates; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; additional risks associated with our thermal heavy oil projects; our ability to compete with other organizations in the oil and gas industry; risks associated with our use of information technology systems; results of litigation; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks of counterparty default; the impact of Indigenous claims; risks associated with expansion into new activities; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2021, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission not later than March 31, 2022 and in our other public filings.

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 on March 1, 2022 and in our other public filings.

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

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

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

MESSAGE TO SHAREHOLDERS

During this period of renewed optimism, we stayed true to our priorities of maintaining capital discipline, maximizing free cash flow and reducing net debt. **Our team has proven to be resilient, focused and totally committed to generating value for shareholders.**

Edward D. LaFehr
President and Chief Executive Officer



This past year we witnessed a remarkable turnaround for the oil and gas industry as economies recovered from the Covid-19 pandemic and energy prices surged. During this period of renewed optimism, we stayed true to our priorities of maintaining capital discipline, maximizing free cash flow and reducing net debt. Our team has proven to be resilient, focused and totally committed to generating value for shareholders.

In 2021, we generated production of just over 80,000 boe/d, above the high end of our annual guidance and delivered record free cash flow⁽¹⁾ of \$421 million. We significantly strengthened our business as we allocated 100% of free cash flow to debt repayment, reducing net debt⁽²⁾ by 24% to \$1.4 billion. Exploration and development expenditures totaled \$313 million, in line with our annual guidance. We also continued to advance our exciting new Clearwater play in northwest Alberta with four of the highest initial rate wells drilled to date in the play.

During 2021, we introduced a five-year plan (2021 to 2025) which highlighted our financial and operational sustainability and free cash flow generating capability. Our base plan at US\$65 WTI will see us invest approximately 50% of our annual adjusted funds flow during the plan period, generate \$2.1 billion of cumulative free cash flow and grow production to approximately 90,000 boe/d, reflecting a 2% to 4% annual production growth rate. Under constant US\$75/bbl and US\$85/bbl pricing scenarios, our expected cumulative free cash flow increases to approximately \$2.8 billion and \$3.4 billion, respectively.

Our business is backstopped by proved developed producing reserves of 129 million boe, proved reserves of 278 million boe and proved plus probable reserves of 451 million boe. In Canada, we have one of the largest conventional oil portfolios, including high operating netback, light oil production in the Viking and low decline, heavy oil production at Peace River and Lloydminster. We also hold a dominant land position in the Pembina Duvernay, which has similar geologic and reservoir characteristics to our Eagle Ford shale asset in the United States. Our position in the Eagle Ford is considered one of the highest quality, lowest-cost U.S. resource plays with outstanding drilling economics.

Clearwater Development

Across all of our core assets, inventory enhancement continues to be a priority. We are also committed to building and maintaining respectful relationships with Indigenous communities and creating opportunities for meaningful economic participation and inclusion. We have now executed two strategic agreements with the Peavine Métis Settlement in the Peace River area that cover 80 sections of land directly to the south of our existing operations. We hold another 45 sections of land with Clearwater potential, giving us 125 sections of prospective lands in the play. This play aligns strongly with our core competencies in heavy oil exploration and multi-lateral development.

Our 2021 appraisal program yielded exceptional results with production increasing from zero at the beginning of 2021 to over 3,000 bbl/d in January 2022. Our 2022 drilling program is underway and we expect to bring 18 wells onstream this year. With continued success, we believe the play ultimately holds the potential for over 200 drilling locations that could support production increasing to over 10,000 bbl/d. The Clearwater generates strong economics with the ability to grow organically while enhancing our free cash flow profile.

Environmental Stewardship

The energy industry and society are undergoing a transition to a low-carbon economy. We believe oil and gas will be instrumental in this energy transition. As a responsible energy producer, we are committed to monitoring greenhouse gas (GHG) emissions from our operations, setting targets to reduce our GHG emissions intensity and pursuing cost-effective decarbonization strategies.

We have established a target to reduce our corporate GHG emission intensity (tonnes of CO₂e per boe) by 65% by 2025, relative to our 2018 baseline. In 2021, we reduced our GHG emissions intensity by 11% over 2020 levels. Our emissions reduction strategy includes increased gas conservation and combustion, reusing associated gas as fuel for field activities, reducing emissions from storage tanks, along with monitoring and preventing fugitive emissions.

Our commitment to responsible development also extends to the retirement of our assets. We plan for full lifecycle development of our properties which includes the restoration, abandonment and reclamation of assets that have reached the end of their productive life. At December 31, 2020, we had an end of life well inventory of approximately 4,500 wells. We have committed to reducing this well inventory to zero by 2040.

Looking Forward

In 2022, we expect to benefit from our diversified oil weighted portfolio and our commitment to allocate capital effectively. Our capital program is designed to generate stable production from our light and heavy oil assets in Canada and the Eagle Ford in the United States, while scaling up development in the Clearwater. Our 2022 guidance remains unchanged as we target production of 80,000 to 83,000 boe/d with exploration and development expenditures of \$400 to \$450 million. Based on the forward strip at time of writing, we expect to generate over \$550 million of free cash flow in 2022.

With continued operating momentum and strong commodity prices, we expect to reach our initial \$1.2 billion net debt target during the second quarter of 2022. As we reach this debt level, we will have reduced our net debt by approximately \$1.1 billion over the past three and a half years. As a result of our significantly improved financial position, we are pleased to introduce the next phase of our enhanced return to shareholders.

For 2022, we expect to allocate approximately 25% of our annual free cash flow to a share buyback program commencing in Q2/2022. 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 to EBITDA ratio⁽³⁾ of 1.0x at a US\$55 WTI price. We feel this will provide us with ultimate flexibility to run our business through the commodity price cycles and generate meaningful returns for all stakeholders. At current prices, we expect to achieve this net debt level by mid-2023, at which point we will consider steps to further enhance shareholder returns.

Baytex's success is due to our dedicated and talented team of employees who are passionate about delivering our strategies and plans to create value for shareholders. Complementing our leadership team and dedicated employees, our Board of Directors is an indispensable source of guidance and support which contribute greatly to our success. We look forward to executing our plans for 2022 for the ongoing benefit of all stakeholders and we thank you for your continued support.

Sincerely,



Edward D. LaFehr

President and Chief Executive Officer

February 24, 2022

- (1) Non-GAAP 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. See "Specified Financial Measures" in the 2021 Annual MD&A for information related to this non-GAAP financial measure, which information is incorporated by reference into this document.
- (2) Capital management measure. See "Specified Financial Measures" in the 2021 Annual MD&A for information related to this measure, which information is incorporated by reference into this document.
- (3) Net debt to EBITDA ratio is comprised of net debt divided by Bank EBITDA. Bank EBITDA is calculated in accordance with our credit facility which is accessible on the SEDAR website at www.sedar.com

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the years ended December 31, 2021 and 2020. This information is provided as of February 24, 2022. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. The results for the three months and year ended December 31, 2021 ("Q4/2021" and "2021") have been compared with the results for the three months and year ended December 31, 2020 ("Q4/2020" and "2020"). This MD&A should be read in conjunction with the Company's audited consolidated financial statements ("consolidated financial statements") for the years ended December 31, 2021 and 2020, together with the accompanying notes and the Annual Information Form ("AIF") for the year ended December 31, 2021. These documents and additional information about Baytex are accessible on the SEDAR website at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov. All amounts are in Canadian dollars, unless otherwise stated, and all tabular amounts are in thousands of Canadian dollars, except for percentages and per common share amounts or as otherwise noted.

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

This MD&A contains forward-looking information and statements along with certain measures which do not have any standardized meaning in accordance with International Financial Reporting Standards ("IFRS") as prescribed by the International Accounting Standards Board. The terms "operating netback", "free cash flow", "average royalty rate", "heavy oil, net of blending and other expense" and "total sales, net of blending and other expense" are specified financial measures that do not have any standardized meaning as prescribed by IFRS and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. This MD&A also contains the terms "adjusted funds flow", "net debt" and "net debt to adjusted funds flow ratio" which are capital management measures. Refer to our advisory on forward-looking information and statements and a summary of our specified financial measures at the end of the MD&A.

BAYTEX ENERGY CORP.

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

2021 ANNUAL HIGHLIGHTS

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

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

(1) *Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.*

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

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

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

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

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

GUIDANCE

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

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

(1) As announced on December 2, 2020.

(2) As announced on April 29, 2021. This guidance reference date included the introduction of a five-year outlook. 2021 guidance was subsequently tightened on November 4, 2021, reflecting year-to-date results, to \$300 to \$315 million for exploration and development expenditures, 79,500 to 80,000 boe/d for production, 18.5% to 19.0% for royalty rates, \$11.25/boe to \$11.75/boe for operating expenses, \$1.10/boe to \$1.15/boe for transportation expenses and \$92 million (\$3.16/boe) for interest expense.

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

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

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

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

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

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

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

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

RESULTS OF OPERATIONS

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

Production

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

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

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

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

Commodity Prices

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

Crude Oil

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

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

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

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

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

Natural Gas

Our U.S. natural gas production is priced in reference to the New York Mercantile Exchange ("NYMEX") natural gas index. The NYMEX natural gas benchmark averaged US\$3.84/mmbtu for 2021 which is higher than US\$2.08/mmbtu for 2020 as strong demand and lower U.S. production resulted in reduced inventory levels for 2021 relative to 2020.

In Canada, we receive natural gas pricing based on the AECO benchmark which continues to trade at a discount to NYMEX as a result of limited market access for Canadian natural gas production. The AECO benchmark averaged \$3.56/mcf during 2021 compared to \$2.24/mcf during 2020. The AECO benchmark was higher in 2021 relative to 2020 due to lower production and increased demand for natural gas which resulted in reduced inventory levels in Canada.

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

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

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.

(2) MEH refers to arithmetic average of the Argus WTI Houston differential weighted index price for the applicable period.

(3) Edmonton par refers to the average posting price for the benchmark MSW crude oil.

(4) WCS refers to the average posting price for the benchmark WCS heavy oil.

(5) AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter ("CGPR").

(6) NYMEX refers to the NYMEX last day average index price as published by the CGPR.

Years Ended December 31

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

Average Realized Sales Prices

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

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

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

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

Our realized NGL price as a percentage of WTI can vary from period to period based on the product mix of our NGL volumes and changes in the market prices of the underlying products. Our realized NGL price was \$35.74/bbl in 2021 or 42% of WTI (expressed in Canadian dollars) compared to \$15.22/bbl or 29% of WTI (expressed in Canadian dollars) in 2020. Our realized NGL price was higher as a percentage of WTI in 2021 relative to 2020 due to strong global demand, incremental LNG export capacity and lower supply of NGLs in 2021.

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

(1) Calculated as light oil and condensate, NGL or natural gas sales divided by barrels of oil equivalent production volume for the applicable period.

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

Petroleum and Natural Gas Sales

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

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

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

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

Royalties

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

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

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

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

(3) Royalties per boe is calculated as royalties divided by barrels of oil equivalent production volume for the applicable period.

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

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

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

Operating Expense

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

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

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

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

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

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

Transportation Expense

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

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

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

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

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

Blending and Other Expense

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

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

Financial Derivatives

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

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

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

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

	Period	Volume	Price/Unit ⁽¹⁾	Index
Oil				
Basis swap	Jan 2022 to Dec 2022	12,000 bbl/d	WTI less US\$12.40/bbl	WCS
Basis swap	Jan 2022 to Dec 2022	4,000 bbl/d	WTI less US\$4.43/bbl	MSW
Basis swap ⁽³⁾	Feb 2022 to Jun 2022	1,000 bbl/d	WTI less US\$3.00/bbl	MSW
Basis swap ⁽³⁾	Mar 2022 to Dec 2022	2,000 bbl/d	WTI less US\$2.88/bbl	MSW
Fixed - Sell	Jan 2022 to Dec 2022	10,000 bbl/d	US\$53.50/bbl	WTI
3-way option ⁽²⁾	Jan 2022 to Dec 2022	1,500 bbl/d	US\$40.00/US\$50.00/US\$58.10	WTI
3-way option ⁽²⁾	Jan 2022 to Dec 2022	2,000 bbl/d	US\$46.00/US\$56.00/US\$66.72	WTI
3-way option ⁽²⁾	Jan 2022 to Dec 2022	2,500 bbl/d	US\$47.00/US\$57.00/US\$67.00	WTI
3-way option ⁽²⁾	Jan 2022 to Dec 2022	2,500 bbl/d	US\$50.00/US\$60.00/US\$70.00	WTI
3-way option ⁽²⁾	Jan 2022 to Dec 2022	2,000 bbl/d	US\$53.00/US\$63.50/US\$72.90	WTI
3-way option ⁽²⁾	Jan 2023 to Dec 2023	2,000 bbl/d	US\$55.00/US\$66.00/US\$84.00	WTI
3-way option ⁽²⁾⁽³⁾	Jan 2023 to Dec 2023	2,500 bbl/d	US\$60.00/US\$75.00/US\$91.54	WTI
Natural Gas				
Fixed - Sell	Jan 2022 to Dec 2022	5,000 GJ/d	\$2.53/GJ	AECO 7A
Fixed - Sell	Jan 2022 to Dec 2022	14,250 GJ/d	\$2.84/GJ	AECO 5A
Fixed - Sell	Jan 2022 to Dec 2022	1,000 mmbtu/d	US\$2.94/mmbtu	NYMEX
3-way option ⁽²⁾	Jan 2022 to Dec 2022	2,500 mmbtu/d	US\$2.25/US\$2.75/US\$3.06	NYMEX
3-way option ⁽²⁾	Jan 2022 to Dec 2022	1,500 mmbtu/d	US\$2.60/US\$2.91/US\$3.56	NYMEX
3-way option ⁽²⁾	Jan 2022 to Dec 2022	2,500 mmbtu/d	US\$2.60/US\$3.00/US\$3.83	NYMEX
3-way option ⁽²⁾	Jan 2022 to Dec 2022	2,500 mmbtu/d	US\$2.65/US\$2.90/US\$3.40	NYMEX
3-way option ⁽²⁾	Jan 2022 to Dec 2022	2,500 mmbtu/d	US\$3.00/US\$3.75/US\$4.40	NYMEX

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

(2) Producer 3-way option consists of a sold call, a bought put and a sold put. To illustrate, in a US\$50.00/US\$60.00/US\$70.00 contract, Baytex receives WTI plus US\$10.00/bbl when WTI is at or below US\$50.00/bbl; Baytex receives US\$60.00/bbl when WTI is between US\$50.00/bbl and US\$60.00/bbl; Baytex receives the market price when WTI is between US\$60.00/bbl and US\$70.00/bbl; and Baytex receives US\$70.00/bbl when WTI is above US\$70.00/bbl.

(3) Contracts entered subsequent to December 31, 2021.

Operating Netback

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

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

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

(2) Refer to Royalties, Operating Expense and Transportation Expense sections in this MD&A for a description of the composition these measures.

(3) Calculated as realized financial derivatives gain (loss) expense divided by barrels of oil equivalent production volume for the applicable period.

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

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

General and Administrative Expense

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

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

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

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

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

Financing and Interest Expense

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

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

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

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

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

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

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

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

Exploration and Evaluation Expense

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

Depletion and Depreciation

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

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

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

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

Impairment

2021 Impairment Reversals

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

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

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

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

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

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

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

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

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

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

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

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

2020 Impairments

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

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

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

Share-Based Compensation Expense

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

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

Foreign Exchange

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

Years Ended December 31

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

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

Income Taxes

Years Ended December 31

<i>(\$ thousands)</i>	2021	2020	Change
Current income tax expense	\$ 1,272	\$ 574	\$ 698
Deferred income tax expense (recovery)	79,968	(160,967)	240,935
Total income tax expense (recovery)	\$ 81,240	\$ (160,393)	\$ 241,633

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

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

As disclosed in the 2020 annual financial statements, certain indirect subsidiaries received reassessments from the Canada Revenue Agency (the "CRA") that deny \$591.0 million of non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. In September 2016, we filed notices of objection with the CRA appealing each reassessment received. There has been no change in the status of these reassessments since an Appeals Officer was assigned to our file in July 2018. We remain confident that our original tax filings are correct and intend to defend these tax filings through the appeals process.

Canadian Tax Pools <i>(\$ thousands)</i>	December 31, 2021	December 31, 2020
Canadian oil and natural gas property expenditures	\$ 406,475	\$ 449,670
Canadian development expenditures	480,814	557,554
Canadian exploration expenditures	—	10,907
Undepreciated capital costs	287,170	347,297
Non-capital losses	996,556	1,015,152
Financing costs and other	12,835	14,780
Total Canadian tax pools	\$ 2,183,850	\$ 2,395,360
U.S. Tax Pools <i>(\$ thousands)</i>		
Depletion	\$ 136,505	\$ 147,160
Intangible drilling costs	1,898	5,521
Tangibles	23,949	39,028
Net operating losses	992,258	1,150,068
Other	152,509	192,495
Total U.S. tax pools	\$ 1,307,119	\$ 1,534,272

Net Income (Loss)

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

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

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

(2) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

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

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

Other Comprehensive Income (Loss)

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

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

Capital Expenditures

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

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

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

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

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

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

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

CAPITAL RESOURCES AND LIQUIDITY

Our capital management objective is to maintain financial flexibility and sufficient sources of liquidity to execute our capital programs, while meeting our short and long-term commitments. We strive to actively manage our capital structure in response to changes in economic conditions. At December 31, 2021, our capital structure was comprised of shareholders' capital, long-term notes, trade and other receivables, trade and other payables and the credit facilities.

In order to manage our capital structure and liquidity, we may from time to time issue equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

The capital intensive nature of our operations requires the maintenance of adequate sources of liquidity to fund ongoing exploration and development. Our capital resources consist primarily of adjusted funds flow, available credit facilities and proceeds received from the divestiture of oil and gas properties.

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

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

Credit Facilities

Our credit facilities include US\$575 million of revolving credit facilities and a \$300 million non-revolving term loan (collectively, the "Credit Facilities"). Our Credit Facilities mature on April 2, 2024 and will automatically be extended to June 4, 2024 providing we have either refinanced, or have the ability to repay, the outstanding 2024 long-term notes with existing credit capacity as of April 1, 2024. At December 31, 2021, we had \$521.5 million of borrowings and letters of credit outstanding under our Credit Facilities that total approximately \$1.0 billion.

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

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

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

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

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

Financial Covenants

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

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

- (1) *"Senior Secured Debt" is calculated in accordance with the credit facility agreements and is defined as the principal amount of the Credit Facilities and other secured obligations identified in the credit agreement. As at December 31, 2021, the Company's Senior Secured Debt totaled \$521.5 million.*
 (2) *"Bank EBITDA" is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expenses, income tax, non-recurring losses, certain specific unrealized and non-cash transactions and is calculated based on a trailing twelve-month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the twelve months ended December 31, 2021 was \$836.9 million.*
 (3) *"Interest coverage" is calculated in accordance with the credit agreement and is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis. Financing and interest expenses for the twelve months ended December 31, 2021 were \$91.8 million.*

Long-Term Notes

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

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

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

Shareholders' Capital

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

Contractual Obligations

We have a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact our adjusted funds flow in an ongoing manner. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of December 31, 2021 and the expected timing for funding these obligations are noted in the table below.

(\$ thousands)	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	\$ 190,692	\$ 190,692	\$ —	\$ —	\$ —
Financial derivatives	134,020	134,020	—	—	—
Credit facilities - principal ^{(1) (2)}	506,514	—	506,514	—	—
Total long-term notes - principal ⁽²⁾	885,920	—	253,120	—	632,800
Interest on long-term notes ⁽³⁾	325,172	69,608	130,868	110,740	13,956
Lease obligations ⁽²⁾	8,014	3,068	3,989	902	55
Processing agreements	6,090	753	890	530	3,917
Transportation agreements	81,182	20,500	37,825	14,673	8,184
Total	\$ 2,137,604	\$ 418,641	\$ 933,206	\$ 126,845	\$ 658,912

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

(2) Principal amount of instruments.

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

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

FOURTH QUARTER OPERATING AND FINANCIAL RESULTS

Three Months Ended December 31

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

(1) Calculated as light oil and condensate, NGL or natural gas sales divided by barrels of oil equivalent production volume for the applicable period.

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

(3) Calculated as royalties, operating or transportation expense divided by barrels of oil equivalent production volume for the applicable period.

(4) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

Three Months Ended December 31

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

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.

(2) MEH refers to arithmetic average of the Argus WTI Houston differential weighted index price for the applicable period.

(3) Edmonton par refers to the average posting price for the benchmark MSW crude oil.

(4) WCS refers to the average posting price for the benchmark WCS heavy oil.

(5) AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter ("CGPR").

(6) NYMEX refers to the NYMEX last day average index price as published by the CGPR.

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

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

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

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

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

(2) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

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

QUARTERLY FINANCIAL INFORMATION

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

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

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

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

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

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

Adjusted funds flow is directly impacted by our average daily production and changes in benchmark commodity prices which are the basis for our realized sales price. Adjusted funds flow⁽¹⁾ improved throughout 2021, to \$214.8 million in Q4/2021, due to strong price realizations and ongoing efforts to control operating and transportation costs.

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

(1) *Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.*

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

ENVIRONMENTAL REGULATIONS

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

Reporting Regulations

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

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at December 31, 2021, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

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

Reserves

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

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

Cash-generating Units ("CGUs")

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

Identification of Impairment and Impairment Reversal Indicators

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

Measurement of Recoverable Amount

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

Exploration and Evaluation ("E&E") Assets

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

Asset Retirement Obligations

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

Income Taxes

Tax regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and there are differing interpretations requiring management judgment. Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in future periods, which requires management judgment. Deferred tax liabilities are recognized when it is considered probable that temporary differences will be payable to tax authorities in future periods, which requires management judgment. Income tax filings are subject to audit and re-assessment and changes in facts, circumstances and interpretations of the standards may result in a material change to the Company's provision for income taxes. Estimates of future income taxes are subject to measurement uncertainty.

NYSE LISTING

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

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

SPECIFIED FINANCIAL MEASURES

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

Non-GAAP Financial Measures

Total sales, net of blending and other expense

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

Operating netback

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

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

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

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

Free cash flow

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

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

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

Non-GAAP Financial Ratios

Heavy oil, net of blending and other expense per bbl

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

Total sales, net of blending and other expense per boe

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

Average royalty rate

Average royalty rate is used to evaluate the performance of our operations from period to period and is comprised of royalties divided by total sales, net of blending and other expense (a non-GAAP financial measure). The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction.

Operating netback per boe

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

Capital Management Measures

Net debt

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

The following table summarizes our calculation of net debt.

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

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

Adjusted funds flow

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

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

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

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As of December 31, 2021, an evaluation was conducted to determine the effectiveness of our "disclosure controls and procedures" (as defined in the United States by Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act") and in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109")) under the supervision of and with the participation of management, including the President and Chief Executive Officer and the Executive Vice President and Chief Financial Officer of Baytex (collectively the "certifying officers"). Based on that evaluation, the certifying officers concluded that our disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that we file or submit under the Exchange Act or under Canadian securities legislation is (i)

recorded, processed, summarized and reported within the time periods specified in the applicable rules and forms and (ii) accumulated and communicated to our management, including the certifying officers, to allow timely decisions regarding the required disclosure.

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

Internal Control Over Financial Reporting

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

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

Management has assessed the effectiveness of our "internal control over financial reporting" as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act and as defined by NI 52-109. The assessment was based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that our internal control over financial reporting was effective as of December 31, 2021.

The effectiveness of our internal control over financial reporting as of December 31, 2021 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their Report of Independent Registered Public Accounting Firm.

Changes in Internal Control over Financial Reporting

No changes were made to our internal control over financial reporting during the year ended December 31, 2021 that have materially affected, or are reasonably likely to materially affect, the internal controls over financial reporting.

SELECTED ANNUAL INFORMATION

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

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

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

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

FORWARD-LOOKING STATEMENTS

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

Specifically, this document contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; for 2022, our capital budget, expected average daily production, expected royalty rate and operating expense, transportation expense, general and administrative expense, cash interest expense, lease expenditures and asset retirement obligations settled; the existence, operation and strategy of our risk management program; the reassessment of our tax filings by the Canada Revenue Agency; that our internally generated adjusted funds flow and our existing undrawn credit facilities will provide sufficient liquidity to sustain our operations and planned capital expenditures; that we may issue or repurchase debt or equity securities from time to time or sell assets; our intent to fund certain financial obligations with cash flow from operations and the expected timing of the financial obligations; our plans with respect to asset retirement obligation activities; and the circumstances in which we may be eligible to deregister our common shares under the Securities Exchange Act of 1934. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

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

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices and price differentials (including the impacts of Covid-19); restrictions or costs imposed by climate change initiatives and the physical risks of climate change; risks associated with our ability to develop our properties and add reserves; the impact of an energy transition on demand for petroleum productions; changes in income tax or other laws or government incentive programs; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; the availability and cost of capital or borrowing; risks associated with a third-party operating our Eagle Ford properties; risks associated with large projects; costs to develop and operate our properties; public perception and its influence on the regulatory regime; current or future control, legislation or regulations; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; regulations regarding the disposal of fluids; risks associated with our hedging activities; variations in interest rates and foreign exchange rates; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; additional risks associated with our thermal heavy oil projects; our ability to compete with other organizations in the oil and gas industry; risks associated with our use of information technology systems; results of litigation; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks of counterparty default; the impact of Indigenous claims; risks associated with expansion into new activities; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2021, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission not later than March 31, 2022 and in our other public filings.

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

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

RISK FACTORS

We are focused on long-term strategic planning and have identified key risks, uncertainties and opportunities associated with our business that can impact the financial and operational results. Listed below is a description of these risks and uncertainties.

Risks Relating to Our Business and Operations

Volatility of oil and natural gas prices and price differentials

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

Prices for crude oil and natural gas fluctuate in response to changes in the supply of, and demand for, crude oil and natural gas, market uncertainty and a variety of additional factors beyond our control. Crude oil prices are primarily determined by international supply and demand. Factors which affect crude oil prices include the actions of OPEC, OPEC+, the condition of the Canadian, United States, European and Asian economies, the impact of pandemics/epidemics (including Covid-19), government regulation, political stability in the Middle East and elsewhere, the supply of crude oil in North America and internationally, the ability to secure adequate transportation for products, the availability of alternate fuel sources and weather conditions. Natural gas prices realized by us are affected primarily in North America by supply and demand, weather conditions, industrial demand, prices of alternate sources of energy and developments related to the market for liquefied natural gas. All of these factors are beyond our control and can result in a high degree of price volatility. Fluctuations in currency exchange rates further compound this volatility when commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars.

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

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

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

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

Regulatory and Policy Initiatives

Our exploration and production facilities and other operational activities emit GHGs. As such, it is highly likely that GHG emissions regulation (including carbon taxes) enacted in jurisdictions where we operate will impact us. In addition, certain of our assets have a higher GHG emissions intensity than others and may be disproportionately impacted.

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

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

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

Physical Risk

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rain fall, hurricanes and wildfires may restrict our ability to access our properties, cause operational difficulties including damage to

machinery and facilities. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of our assets are located where they are exposed to forest fires, floods, heavy rains, hurricanes and other extreme weather conditions which can lead to significant downtime, damage to such assets and/or increased costs of construction and maintenance. Moreover, extreme weather conditions may lead to disruptions in our ability to transport produced oil and natural gas as well as goods and services in our supply chain.

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

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

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

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

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

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

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

In addition, tax authorities having jurisdiction over us or our Shareholders may disagree with the manner in which we calculate our income for tax purposes or could change their administrative practices to our detriment or the detriment of our Shareholders. We file all required income tax returns and believe that we are in full compliance with the applicable tax legislation. However, such returns are subject to audit and reassessment by the applicable taxation authority. Any such reassessment may have an impact on current and future taxes payable. At present, the Canadian tax authorities have reassessed the returns of certain of our subsidiaries.

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

We deliver our products through gathering, processing and pipeline systems which we do not own and purchasers of our products rely on third party infrastructure to deliver our products to market. The lack of access to capacity in any of the gathering, processing and pipeline systems could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. Alternately, a substantial decrease in the use of such systems can increase the cost we incur to use them. In addition, many of the pipeline systems that we use are controlled by a single company and rates are set through a regulatory process, as a result we are subject to the outcome of those regulatory processes. Any significant change in market factors, regulatory decisions or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could harm our business and, in turn, our financial condition.

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

that short-term operational constraints on pipeline systems, arising from pipeline interruption and/or increased supply of crude oil, will not occur.

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

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

Failure to retain or replace our leadership and key personnel may have an adverse affect on our business

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

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

The business of exploring for, developing or acquiring reserves is capital intensive. If external sources of capital (including, but not limited to, debt and equity financing) become limited or unavailable on commercially reasonable terms, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves may be impaired. Unpredictable financial markets and the associated credit impacts may impede our ability to secure and maintain cost effective financing and limit our ability to achieve timely access to capital on acceptable terms and conditions. If external sources of capital become limited or unavailable, our ability to make capital investments, continue our business plan, meet all of our financial obligations as they come due and maintain existing properties may be impaired.

Our ability to obtain additional capital is dependent on, among other things, a general interest in energy industry investments and, in particular, interest in our securities along with our ability to maintain our credit ratings. If we are unable to maintain our indebtedness and financial ratios at levels acceptable to our credit rating agencies, or should our business prospects deteriorate, our credit ratings could be downgraded. Additionally, from time to time, our securities may not meet the investment criteria or characteristics of a particular institutional or other investor, including institutional investors who are not willing or able to hold securities of oil and gas companies for reasons unrelated to financial or operational performance. This may include changes to market-based factors or investor strategies, including ESG, or responsible investing criteria/rankings (for example, ESG, social impact or environmental scores), the implementation of new financial market regulations and fossil fuel divestment initiatives undertaken by governments, pension funds and/or other institutional investors. These events would adversely affect the value of our outstanding securities and existing debt and our ability to obtain new financing, and may increase our borrowing costs.

From time to time we may enter into transactions which may be financed in whole or in part with debt or equity. The level of our indebtedness from time to time, could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise. Additionally, from time to time, we may issue securities from treasury in order to reduce debt, complete acquisitions and/or optimize our capital structure.

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

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

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

To the extent that the capital expenditure requirements related to our Eagle Ford acreage exceeds our budgeted amounts, it may reduce the amount of capital we have available to invest in our other assets. We have the ability to elect whether or not to participate in well locations proposed by Marathon Oil on an individual basis. If we elect to not participate in a well location, we

forgo any revenue from such well until Marathon Oil has recouped, from our working interest share of production from such well, 300% to 500% of our working interest share of the cost of such well.

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

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

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

Our development and operating costs are affected by a number of factors including, but not limited to: price inflation, access to skilled and unskilled labour, availability of equipment, scheduling delays, trucking and fuel costs, failure to maintain quality construction standards, the cost of new technologies and supply chain disruptions. Labour costs, natural gas, electricity, water, diluent and chemicals are examples of some of the operating and other costs that are susceptible to significant fluctuation. Increases to development and operating costs could have a material adverse effect on our financial condition, results of operations or prospects.

Public perception and its influence on the regulatory regime

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

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

Operations

The oil and gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government. All such controls, regulations and legislation are subject to revocation, amendment or administrative change, some of which have historically been material and in some cases materially adverse. The exercise of discretion by government authorities under existing controls, legislation or regulations, the implementation of new controls, legislation or regulations or the modification of existing controls, legislation or regulations affecting the oil and gas industry could reduce demand for crude oil and natural gas, increase our costs, or delay or restrict our operations, all of which could have a material adverse effect on our financial condition, results of operations or prospects.

Environment

All phases of our operations are subject to environmental and health and safety regulation pursuant to a variety of federal, provincial, state and municipal laws and regulations (collectively, "**environmental regulations**") governing occupational health and safety, the spill, release or emission of substances into the environment or otherwise relating to environmental protection. Environmental regulations require that wells, facility sites and other properties associated with our operations be constructed, operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations require the submission and approval of environmental impact assessments or permit applications. Environmental regulations impose restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. The jurisdictions where we operate have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. Changes to the requirements of liability management programs may result in significant increases to the security that must be posted, the timing of our abandonment and reclamation operations and the costs associated with such operations.

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

and enforcement, larger penalties and liability and increased capital expenditures and operating costs, which could have a material adverse effect on our financial condition, results of operations or prospects.

Foreign Investment and Competition Act Legislation

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Our reserves as at December 31, 2021 are estimated using forecast prices and costs. If we realize lower prices for crude oil, natural gas liquids and natural gas and they are substituted for the estimated price assumptions, the present value of estimated future net revenues for our reserves and net asset value would be reduced and the reduction could be significant. Our actual production, revenues, royalties, taxes and development, abandonment and operating expenditures with respect to our reserves will likely vary from such estimates, and such variances could be material.

Estimates of reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations in the previously estimated reserves and such variances could be material.

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

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

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

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

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

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

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

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

Our information technology systems are subject to certain risks

We utilize a number of information technology systems for the administration and management of our business and are subject to a variety of information technology and system risks as a part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Corporation's information technology systems by third parties or insiders. If our ability to access and use these systems is interrupted and cannot be quickly and easily restored then such event could have a material adverse effect on us. Furthermore, although the Corporation has security measures and controls in place to mitigate these risks, a breach of its security measures and/or a loss of information could occur and result in a loss of material and confidential information and reputation, breach of privacy laws, and/or disruption to business activities. The significance of any such event is difficult to quantify but may in certain circumstances be material and could have a material adverse effect on the Corporation's business, financial condition and results of operations.

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

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

Our Credit Facilities may not provide sufficient liquidity and a failure to renew our Credit Facilities at maturity could adversely affect our financial condition

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

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

We are required to comply with the covenants in our Credit Facilities and the Senior Notes. If we fail to comply with such covenants, are unable to repay or refinance amounts owned at maturity or pay the debt service charges or otherwise commit an event of default, such as bankruptcy, it could result in the seizure and/or sale of our assets by our creditors. The proceeds from any sale of our assets would be applied to satisfy amounts owed to the secured creditors and then unsecured creditors. Only after the proceeds of that sale were applied towards our debt would the remainder, if any, be available for the benefit of our Shareholders.

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

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

Indigenous Claims

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

Expansion into New Activities

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

Risks Related to Ownership of our Securities

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

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

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

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

Certain Risks for United States and other non-resident Shareholders

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

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

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

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

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

Probable reserves have a lower certainty of recovery than proved reserves. The SEC requires oil and gas issuers in their filings with the SEC to disclose only proved reserves but permits the optional disclosure of probable reserves. The SEC definitions of proved reserves and probable reserves are different than NI 51-101; therefore, our disclosure of proved, probable and proved plus probable reserves may not be comparable to United States standards.

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

There is additional taxation applicable to non-residents

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

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Baytex Energy Corp. (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision of our President and Chief Executive Officer and our Executive Vice President and Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on our assessment, we have concluded that as of December 31, 2021, our internal control over financial reporting was effective.

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

The effectiveness of the Company's internal control over financial reporting as of December 31, 2021 has been audited by KPMG LLP, the Company's Independent Registered Public Accounting Firm, who also audited the Company's consolidated financial statements for the year ended December 31, 2021.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

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

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

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

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

/s/ Edward D. LaFehr

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

/s/ Rodney D. Gray

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

February 24, 2022

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated statements of financial position of Baytex Energy Corp. (and subsidiaries) (the “Company”) as of December 31, 2021 and 2020, the related consolidated statements of income (loss) and comprehensive income (loss), changes in equity, and cash flows for the years then ended, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and its financial performance and its cash flows for the years then ended, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company’s internal control over financial reporting as of December 31, 2021, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 24, 2022 expressed an unqualified opinion on the effectiveness of the Company’s internal control over financial reporting.

Basis for Opinion

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

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

Critical Audit Matters

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

Assessment of the recoverable amount of oil and gas properties

As discussed in note 6 to the consolidated financial statements, the Company recorded an impairment reversal of \$1,537 million related to the Company’s Conventional, Peace River, Lloydminster, Viking and Eagle Ford cash generating units (CGUs). The Company identified indicators of impairment reversal as of December 31, 2021 for each of the CGUs and therefore determined the recoverable amount as of December 31, 2021 of each of the CGUs. The determination of recoverable amount of a CGU involves numerous estimates, including cash flows associated with estimated proved and probable oil and gas reserves of the CGU (“CGU reserves”) and the discount rate. The estimation of proved and probable oil and gas reserves involves the expertise of independent reserves evaluators, who take into consideration assumptions related to forecasted production volumes, royalty, operating and capital costs and commodity prices (collectively “reserve assumptions”). The Company engages independent reserves evaluators to estimate CGU reserves.

We identified the assessment of the recoverable amount of each of the Company’s CGUs as a critical audit matter. Minor changes in reserve assumptions and discount rates could have had a significant impact on the estimate of recoverable amounts and the resulting impairment reversal of the CGUs. A high degree of auditor judgment was required to evaluate the Company’s estimates of CGU reserves, and related reserve assumptions, and the discount rates, which were inputs into the calculation of recoverable amounts. Additionally, the evaluation of these estimates required involvement of valuation professionals with specialized skills and knowledge.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the critical audit matter. This included controls related to:

- the Company's determination of the recoverable amount of each of the CGUs, including the discount rate
- the Company's determination of reserve assumptions of the CGU reserves and resulting cash flows.

We evaluated the competence, capabilities and objectivity of the independent reserves evaluators engaged by the Company. We evaluated the methodology used by the independent reserves evaluators to estimate the CGU reserves for compliance with regulatory standards. We compared the current year actual CGU production volumes, royalty, operating and capital costs to those estimates used in the prior year estimate of proved reserves by CGU to assess the Company's ability to accurately forecast. We assessed the forecasted commodity prices used in the estimate of the CGU reserves by comparing them to those published by other reserve engineering companies. We assessed the forecasted production volumes and forecasted royalty, operating and capital costs assumptions used in the current year estimate of the CGU reserves by comparing them to historical results. We involved valuation professionals with specialized skills and knowledge, who assisted in:

- evaluating the Company's determination of discount rates by comparing the discount rate against publicly available market data for comparable assets and assessing the resulting discount rate
- evaluating the Company's estimate of aggregate recoverable amount of all CGUs by comparing the implied enterprise value to publicly available market data.

Impact of estimated oil and gas reserves on depletion expense related to oil and gas properties

As discussed in note 3 to the consolidated financial statements, the Company depletes its oil and gas properties using the unit-of-production method by depletable area. Under such method, capitalized costs are depleted over estimated proved and probable oil and gas reserves by depletable area ("area reserves"). As discussed in note 6 to the consolidated financial statements, the Company recorded depletion expense related to oil and gas properties of \$459 million for the year ended December 31, 2021. The estimation of area reserves requires the expertise of independent reserves evaluators who take into consideration reserve assumptions. The Company engages independent reserves evaluators to estimate area reserves.

We identified the assessment of the impact of estimated area reserves on depletion expense related to oil and gas properties as a critical audit matter. Changes in assumptions used to estimate area reserves could have had a significant impact on the calculation of depletion expense of the depletable area. A high degree of auditor judgment was required in evaluating the area reserves, and related reserve assumptions, which were used in the calculation of depletion expense.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the critical audit matter. This included controls related to:

- the Company's calculation of depletion expense
- the Company's determination of reserve assumptions and resulting area reserves.

We assessed the calculation of depletion expense for compliance with International Financial Reporting Standards as issued by the International Accounting Standards Board. We evaluated the competence, capabilities and objectivity of the independent reserves evaluators engaged by the Company. We evaluated the methodology used by the independent reserves evaluators to estimate area reserves for compliance with regulatory standards. We compared current year actual area production volumes, royalty, operating and capital costs to those estimates used in the prior year estimate of proved reserves by area to assess the Company's ability to accurately forecast. We assessed the forecasted commodity prices used in the estimate of area reserves by comparing them to those published by other reserves engineering companies. We assessed the forecasted production volumes and forecasted royalty, operating and capital costs assumptions used in the estimate of area reserves by comparing them to historical results.

/s/ KPMG LLP

Chartered Professional Accountants

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

Calgary, Canada
February 24, 2022

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on Internal Control Over Financial Reporting

We have audited Baytex Energy Corp.'s (and subsidiaries') (the "Company") internal control over financial reporting as of December 31, 2021, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated statements of financial position of the Company as of December 31, 2021 and 2020, the related consolidated statements of income (loss) and comprehensive income (loss), changes in equity, and cash flows for the years then ended, and the related notes (collectively, the consolidated financial statements), and our report dated February 24, 2022 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

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

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ KPMG LLP

Chartered Professional Accountants

Calgary, Canada
February 24, 2022

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

As at	Notes	December 31, 2021	December 31, 2020
ASSETS			
Current assets			
Trade and other receivables		\$ 173,409	\$ 107,477
Financial derivatives	17	8,654	5,057
		182,063	112,534
Non-current assets			
Exploration and evaluation assets	5	172,824	191,865
Oil and gas properties	6	4,464,371	3,077,548
Other plant and equipment		7,121	7,996
Lease assets		8,264	11,098
Deferred income tax asset	14	—	7,055
		\$ 4,834,643	\$ 3,408,096
LIABILITIES			
Current liabilities			
Trade and other payables		\$ 190,692	\$ 155,955
Financial derivatives	17	134,020	26,792
Lease obligations		2,938	4,289
Asset retirement obligations	9	11,080	11,820
		338,730	198,856
Non-current liabilities			
Credit facilities	7	505,171	649,221
Long-term notes	8	874,527	1,132,868
Lease obligations		4,827	6,787
Asset retirement obligations	9	732,603	748,563
Deferred income tax liability	14	167,456	93,588
		2,623,314	2,829,883
SHAREHOLDERS' EQUITY			
Shareholders' capital	10	5,736,593	5,729,418
Contributed surplus		13,559	14,345
Accumulated other comprehensive income		632,103	618,976
Deficit		(4,170,926)	(5,784,526)
		2,211,329	578,213
		\$ 4,834,643	\$ 3,408,096

Commitments (note 19)

See accompanying notes to the consolidated financial statements.

/s/ Mark R. Bly

Mark R. Bly
Director, Baytex Energy Corp.

/s/ Jennifer A. Maki

Jennifer A. Maki
Director, Baytex Energy Corp.

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

Years Ended December 31	Notes	2021	2020
Revenue, net of royalties			
Petroleum and natural gas sales	13	\$ 1,868,195	\$ 975,477
Royalties		(339,156)	(163,735)
		1,529,039	811,742
Expenses			
Operating		343,002	331,345
Transportation		32,261	28,437
Blending and other		85,689	48,381
General and administrative		40,804	34,268
Exploration and evaluation	5	15,212	14,011
Depletion and depreciation		464,580	486,380
Impairment (impairment reversal)	5, 6	(1,542,414)	2,360,220
Share-based compensation	11	11,130	9,469
Financing and interest	15	111,159	125,441
Financial derivatives loss (gain)	17	287,872	(29,336)
Foreign exchange (gain) loss	16	(2,868)	8,688
Gain on dispositions		(9,666)	(901)
Other income		(2,562)	(5,304)
		(165,801)	3,411,099
Net income (loss) before income taxes		1,694,840	(2,599,357)
Income tax expense (recovery)	14		
Current income tax expense		1,272	574
Deferred income tax expense (recovery)		79,968	(160,967)
		81,240	(160,393)
Net income (loss)		\$ 1,613,600	\$ (2,438,964)
Other comprehensive income (loss)			
Foreign currency translation adjustment		13,127	62,752
Comprehensive income (loss)		\$ 1,626,727	\$ (2,376,212)
Net income (loss) per common share			
Basic	12	\$ 2.86	\$ (4.35)
Diluted		\$ 2.82	\$ (4.35)
Weighted average common shares			
Basic	12	563,674	560,657
Diluted		571,610	560,657

See accompanying notes to the consolidated financial statements.

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

	Notes	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income	Deficit	Total equity
Balance at December 31, 2019		\$ 5,718,835	\$ 17,712	\$ 556,224	\$ (3,345,562)	\$ 2,947,209
Vesting of share awards	10	10,583	(10,583)	—	—	—
Share-based compensation	11	—	7,216	—	—	7,216
Comprehensive income (loss)		—	—	62,752	(2,438,964)	(2,376,212)
Balance at December 31, 2020		\$ 5,729,418	\$ 14,345	\$ 618,976	\$ (5,784,526)	\$ 578,213
Vesting of share awards	10	7,175	(7,175)	—	—	—
Share-based compensation	11	—	6,389	—	—	6,389
Comprehensive income		—	—	13,127	1,613,600	1,626,727
Balance at December 31, 2021		\$ 5,736,593	\$ 13,559	\$ 632,103	\$ (4,170,926)	\$ 2,211,329

See accompanying notes to the consolidated financial statements.

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

Years Ended December 31	Notes	2021	2020
CASH PROVIDED BY (USED IN):			
Operating activities			
Net income (loss)		\$ 1,613,600	\$ (2,438,964)
Adjustments for:			
Share-based compensation	11	6,389	7,216
Unrealized foreign exchange (gain) loss	16	(1,905)	9,232
Exploration and evaluation	5	15,212	14,011
Depletion and depreciation		464,580	486,380
Impairment (impairment reversal)	5, 6	(1,542,414)	2,360,220
Non-cash financing, accretion and early redemption expense	15	19,090	18,907
Non-cash other income	9	(2,857)	(2,128)
Unrealized financial derivatives loss	17	103,631	18,500
Gain on dispositions		(9,666)	(901)
Deferred income tax expense (recovery)	14	79,968	(160,967)
Asset retirement obligations settled	9	(6,662)	(7,168)
Change in non-cash working capital	18	(26,582)	48,758
Cash flows from operating activities		712,384	353,096
Financing activities			
(Decrease) increase in credit facilities	7	(145,321)	143,248
Payments on lease obligations		(4,334)	(5,925)
Net proceeds from issuance of long-term notes	8	—	652,150
Redemption of long-term notes	8	(251,969)	(833,672)
Cash flows used in financing activities		(401,624)	(44,199)
Investing activities			
Additions to exploration and evaluation assets	5	(3,298)	(4,490)
Additions to oil and gas properties	6	(310,005)	(275,850)
Additions to other plant and equipment		(907)	(2,280)
Property acquisitions		(1,557)	—
Proceeds from dispositions		7,804	182
Change in non-cash working capital	18	(2,797)	(32,031)
Cash flows used in investing activities		(310,760)	(314,469)
Change in cash		—	(5,572)
Cash, beginning of year		—	5,572
Cash, end of year		\$ —	\$ —
Supplementary information			
Interest paid		\$ 93,114	\$ 102,358
Income taxes paid		\$ 253	\$ 1,155

See accompanying notes to the consolidated financial statements.

Baytex Energy Corp.

Notes to the Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

(all tabular amounts in thousands of Canadian dollars, except per common share amounts)

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

The consolidated financial statements were approved by the Board of Directors of Baytex on February 24, 2022.

The consolidated financial statements have been prepared on a historical cost basis, with the exception of certain fair value measurements noted in the accounting policies set forth below. The consolidated financial statements are presented in Canadian dollars which is the 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 where otherwise indicated.

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 year ended December 31, 2021, the global economy continued to show signs of recovery from the impacts of the COVID-19 pandemic. Global spot prices for crude oil have recovered and now exceed pre-pandemic levels as optimism for demand recovery improves with limited production growth from independent producers and ongoing OPEC+ production curtailments. While we have benefited from these improvements in crude oil prices there is a degree of uncertainty related to COVID-19 that has been considered in our estimates for the period ended December 31, 2021.

Environmental 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.

Measurement Uncertainty and Judgments

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

Reserves

The Company uses estimates of oil, natural gas and natural gas liquids ("NGL") reserves in the calculation of depletion, evaluating the recoverability of deferred income tax assets and in the determination of fair value estimates for non-financial assets. The process to estimate reserves is complex and requires significant judgment. Estimates of the Company's reserves are

evaluated annually by independent reserves evaluators and represent the estimated recoverable quantities of oil, natural gas and NGL and the related net cash flows. This evaluation of reserves is prepared in accordance with the reserves definition contained in National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" and the Canadian Oil and Gas Evaluation Handbook.

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

Cash-generating Units ("CGUs")

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

Identification of Impairment and Impairment Reversal Indicators

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

Measurement of Recoverable Amount

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

Exploration and Evaluation ("E&E") Assets

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

Asset Retirement Obligations

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

Income Taxes

Tax regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and there are differing interpretations requiring management judgment. Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in future periods, which requires management judgment. Deferred tax liabilities are recognized when it is considered probable that temporary differences will be payable to tax authorities in future periods, which requires management judgment. Income tax filings are subject to audit and re-assessment and changes in facts, circumstances and interpretations of the standards may result in a material change to the Company's provision for income taxes. Estimates of future income taxes are subject to measurement uncertainty.

3. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

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

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

Business Combinations

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

Revenue Recognition

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

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

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

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

E&E Assets

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

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

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

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

Oil and Gas Properties

Oil and gas properties are initially recorded at cost and include the costs to acquire, develop, complete geological and geophysical surveys, drill wells, and construct and install infrastructure including wellhead equipment and processing facilities.

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

Depletion and Depreciation

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

Impairment and Impairment Reversals

Non-financial Assets

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

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

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

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

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

Asset Retirement Obligations

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

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

Foreign Currency Translation

Foreign Transactions

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

Foreign Operations

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

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

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

Financial Instruments

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

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

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

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

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

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

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

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

Fair Value of Financial Instruments

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

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

Income Taxes

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

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

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

Share-based Compensation Plans

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

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

The Company has a cash-settled incentive award plan (the "Incentive Award Plan") pursuant to which incentive awards may be granted to officers and employees of the Company and its subsidiaries. Each incentive award entitles the holder 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.

4. SEGMENTED FINANCIAL INFORMATION

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

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

Years Ended December 31	Canada		U.S.		Corporate		Consolidated	
	2021	2020	2021	2020	2021	2020	2021	2020
Revenue, net of royalties								
Petroleum and natural gas sales	\$ 1,128,137	\$ 571,741	\$ 740,058	\$ 403,736	\$ —	\$ —	\$ 1,868,195	\$ 975,477
Royalties	(121,306)	(46,064)	(217,850)	(117,671)	—	—	(339,156)	(163,735)
	1,006,831	525,677	522,208	286,065	—	—	1,529,039	811,742
Expenses								
Operating	257,658	247,050	85,344	84,295	—	—	343,002	331,345
Transportation	32,261	28,437	—	—	—	—	32,261	28,437
Blending and other	85,689	48,381	—	—	—	—	85,689	48,381
General and administrative	—	—	—	—	40,804	34,268	40,804	34,268
Exploration and evaluation	15,212	14,011	—	—	—	—	15,212	14,011
Depletion and depreciation	303,135	309,420	155,806	169,439	5,639	7,521	464,580	486,380
Impairment (reversal) loss	(1,100,000)	1,737,000	(442,414)	623,220	—	—	(1,542,414)	2,360,220
Share-based compensation	—	—	—	—	11,130	9,469	11,130	9,469
Financing and interest	—	—	—	—	111,159	125,441	111,159	125,441
Financial derivatives loss (gain)	—	—	—	—	287,872	(29,336)	287,872	(29,336)
Foreign exchange (gain) loss	—	—	—	—	(2,868)	8,688	(2,868)	8,688
(Gain) loss on dispositions	(9,856)	(901)	190	—	—	—	(9,666)	(901)
Other (income) expense	(2,857)	(2,128)	—	—	295	(3,176)	(2,562)	(5,304)
	(418,758)	2,381,270	(201,074)	876,954	454,031	152,875	(165,801)	3,411,099
Net income (loss) before income taxes	1,425,589	(1,855,593)	723,282	(590,889)	(454,031)	(152,875)	1,694,840	(2,599,357)
Income tax expense (recovery)								
Current income tax (recovery) expense	(548)	469	1,820	105	—	—	1,272	574
Deferred income tax expense (recovery)	86,928	(77,201)	72,913	(57,199)	(79,873)	(26,567)	79,968	(160,967)
	86,380	(76,732)	74,733	(57,094)	(79,873)	(26,567)	81,240	(160,393)
Net income (loss)	\$ 1,339,209	\$(1,778,861)	\$ 648,549	\$(533,795)	\$ (374,158)	\$(126,308)	\$ 1,613,600	\$(2,438,964)
Additions to exploration and evaluation assets								
	3,298	4,490	—	—	—	—	3,298	4,490
Additions to oil and gas properties								
	204,912	170,462	105,093	105,388	—	—	310,005	275,850
Property acquisitions								
	1,557	—	—	—	—	—	1,557	—
Proceeds from dispositions								
	(7,211)	(182)	(593)	—	—	—	(7,804)	(182)

As at	December 31, 2021		December 31, 2020	
Canadian assets	\$	2,658,281	\$	1,646,412
U.S. assets		2,152,323		1,737,533
Corporate assets		24,039		24,151
Total consolidated assets	\$	4,834,643	\$	3,408,096

5. EXPLORATION AND EVALUATION ASSETS

	December 31, 2021	December 31, 2020
Balance, beginning of year	\$ 191,865	\$ 320,210
Capital expenditures	3,298	4,490
Property acquisitions	1,100	—
Divestitures	(166)	—
Property swaps	408	468
Impairment	—	(113,058)
Exploration and evaluation expense ⁽¹⁾	(15,212)	(14,011)
Transfers to oil and gas properties (note 6)	(7,727)	(8,585)
Foreign currency translation	(742)	2,351
Balance, end of year	\$ 172,824	\$ 191,865

(1) Exploration and evaluation expense balance consists of land expiries as at December 31, 2021.

At December 31, 2021, there were no indicators of impairment or impairment reversal for exploration and evaluation assets in any of the Company's CGUs.

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

	Impairment at March 31, 2020
Conventional CGU	\$ 4,000
Peace River CGU	20,000
Lloydminster CGU	42,000
Viking CGU	13,000
Eagle Ford CGU	48,861
	\$ 127,861

At December 31, 2020, the Company estimated the recoverable amount of the exploration and evaluation assets within each of its six CGUs due to the ongoing volatility in future oil and natural gas prices. The recoverable amount supported the carrying amount for the Conventional, Peace River, Lloydminster, and Duvernay CGUs and no impairment loss or impairment reversal was recorded. The recoverable amount for the Viking and Eagle Ford CGUs exceeded their carrying amounts which resulted in an impairment reversal of \$14.8 million at December 31, 2020. The recoverable amount of each CGU was based on its FVLCD and was estimated with reference to arm's length transaction in comparable locations and the discounted cash flows associated with the Company's future development plans. The following table indicates the impairment reversal booked for the Viking and Eagle Ford CGUs at December 31, 2020.

	Impairment reversal at December 31, 2020
Viking CGU	\$ 2,000
Eagle Ford CGU	12,803
	\$ 14,803

6. OIL AND GAS PROPERTIES

	Cost	Accumulated depletion	Net book value
Balance, December 31, 2019	\$ 11,128,297	\$ (5,740,408)	\$ 5,387,889
Capital expenditures	275,850	—	275,850
Transfers from exploration and evaluation assets (note 5)	8,585	—	8,585
Change in asset retirement obligations (note 9)	94,994	—	94,994
Property swaps	(1,190)	178	(1,012)
Impairment	—	(2,247,162)	(2,247,162)
Foreign currency translation	(82,860)	120,123	37,263
Depletion	—	(478,859)	(478,859)
Balance, December 31, 2020	\$ 11,423,676	\$ (8,346,128)	\$ 3,077,548
Capital expenditures	310,005	—	310,005
Property acquisitions	274	—	274
Divestitures	(37,835)	32,844	(4,991)
Property swaps	(26,131)	25,900	(231)
Transfers from exploration and evaluation assets (note 5)	7,727	—	7,727
Change in asset retirement obligations (note 9)	(12,222)	—	(12,222)
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

Baytex recorded total impairment reversals related to oil and gas properties of \$1.5 billion for the year ended December 31, 2021 and impairment losses related to oil and gas properties of \$2.2 billion for the year ended December 31, 2020.

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

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

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

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

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%.

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

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

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

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

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

2020 Impairments

At December 31, 2020, the Company estimated the recoverable amount of each of its six CGUs due to the volatility in commodity prices during the year and a reduction in future development costs per well for the Viking and Eagle Ford CGUs. The recoverable amount supported the carrying amount for the Conventional, Peace River, Lloydminster, and Duvernay CGUs and no impairment or impairment reversal was recorded. The recoverable amount for the Viking and Eagle Ford CGUs exceeded their carrying amounts which resulted in an impairment reversal of \$341.3 million recorded at December 31, 2020. 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. The after-tax discount rates applied to the cash flows were between 10% and 17%.

At December 31, 2020, the recoverable amount of the Company's CGUs were calculated using the following benchmark reference prices for the years 2021 to 2030 adjusted for commodity differentials specific to the Company. The prices and costs subsequent to 2030 have been adjusted for inflation at an annual rate of 2%.

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
WTI crude oil (US\$/bbl)	47.17	50.17	53.17	54.97	56.07	57.19	58.34	59.50	60.69	61.91
WCS heavy oil (\$/bbl)	44.63	48.18	52.10	54.10	55.19	56.29	57.42	58.57	59.74	60.93
LLS crude oil (US\$/bbl)	49.50	52.85	55.87	57.69	58.82	59.97	61.15	62.34	63.56	64.83
Edmonton par oil (\$/bbl)	55.76	59.89	63.48	65.76	67.13	68.53	69.95	71.40	72.88	74.34
Henry Hub gas (US\$/mmbtu)	2.83	2.87	2.90	2.96	3.02	3.08	3.14	3.20	3.26	3.33
AECO gas (\$/mmbtu)	2.78	2.70	2.61	2.65	2.70	2.76	2.81	2.87	2.92	2.98
Exchange rate (CAD/USD)	1.30	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31

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

	Recoverable amount	Impairment reversal	Change in discount rate of 1%	Change in oil price of \$2.50/bbl	Change in gas price of \$0.25/mcf
Conventional CGU	\$ 54,265	\$ —	\$ 1,000	\$ 3,000	\$ 9,000
Peace River CGU	104,225	—	1,000	49,500	3,000
Lloydminster CGU	212,979	—	7,000	57,500	500
Duvernay CGU	70,491	—	5,500	12,000	1,500
Viking CGU	1,026,026	116,000	34,500	106,500	5,000
Eagle Ford CGU	1,609,562	225,326	91,600	157,500	38,400
	\$ 3,077,548	\$ 341,326	\$ 140,600	\$ 386,000	\$ 57,400

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

At March 31, 2020, the recoverable amount of the Company's CGUs were calculated using the following benchmark reference prices for the years 2020 to 2029 adjusted for commodity differentials specific to the Company. The prices and costs subsequent to 2029 have been adjusted for inflation at an annual rate of 2%.

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

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

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

7. CREDIT FACILITIES

	December 31, 2021	December 31, 2020
Credit facilities - U.S. dollar denominated ⁽¹⁾	\$ 156,332	\$ 140,815
Credit facilities - Canadian dollar denominated	350,182	510,358
Credit facilities - principal ⁽²⁾	\$ 506,514	\$ 651,173
Unamortized debt issuance costs	(1,343)	(1,952)
Credit facilities	\$ 505,171	\$ 649,221

(1) U.S. dollar denominated credit facilities balance was US\$123.5 million as at December 31, 2021 (December 31, 2020 - US\$110.4 million).

(2) The decrease in the principal amount of the credit facilities outstanding from December 31, 2020 to December 31, 2021 is the result of net repayments of \$145.3 million and an increase in the reported amount of U.S. denominated debt of \$0.7 million due to foreign exchange.

Baytex has US\$575 million of revolving credit facilities (the "Revolving Facilities") and a \$300 million non-revolving secured term loan (the "Term Loan") (collectively the "Credit Facilities"). The Credit Facilities mature on April 2, 2024 and will automatically be extended to June 4, 2024 providing Baytex has either refinanced, or has the ability to repay, the outstanding 2024 long-term notes with existing credit capacity as of April 1, 2024.

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

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

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

The weighted average interest rate on the Credit Facilities was 2.1% for the year ended December 31, 2021 (2.4% for the year ended December 31, 2020).

At December 31, 2021, Baytex had \$15.0 million of outstanding letters of credit under the Credit Facilities (December 31, 2020 - \$15.0 million).

At December 31, 2021, Baytex was in compliance with all of the covenants contained in the Credit Facilities and is forecasting compliance with these covenants based on current forward commodity prices. The following table summarizes the financial covenants applicable to the Revolving Facilities and Baytex's compliance therewith as at December 31, 2021.

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

- (1) "Senior Secured Debt" is calculated in accordance with the credit facility agreements and is defined as the principal amount of the credit facilities and other secured obligations identified in the credit agreement. As at December 31, 2021, the Company's Senior Secured Debt totaled \$521.5 million.
- (2) "Bank EBITDA" is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expenses, income tax, non-recurring losses, certain specific unrealized and non-cash transactions and is calculated based on a trailing twelve-month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the year ended December 31, 2021 was \$836.9 million.
- (3) "Interest coverage" is calculated in accordance with the credit agreement and is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis. Financing and interest expenses for the year ended December 31, 2021 was \$91.8 million.

8. LONG-TERM NOTES

	December 31, 2021	December 31, 2020
5.625% notes (US\$200,000 – principal) due June 1, 2024	253,120	510,200
8.75% notes (US\$500,000 – principal) due April 1, 2027	632,800	637,750
Total long-term notes - principal ⁽¹⁾	\$ 885,920	\$ 1,147,950
Unamortized debt issuance costs	(11,393)	(15,082)
Total long-term notes - net of unamortized debt issuance costs	\$ 874,527	\$ 1,132,868

- (1) The decrease in the principal amount of long-term notes outstanding from December 31, 2020 to December 31, 2021 is the result of principal repayments of \$249.4 million and changes in the reported amount of U.S. denominated debt of \$12.6 million.

During 2021, Baytex repurchased and cancelled principal notes totaling US\$200 million of the 5.625% Notes and recorded early redemption expense of \$1.9 million. As at December 31, 2021, there was a total of US\$200.0 million of the 5.625% Notes that remained outstanding.

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

The long-term notes do not contain any significant financial maintenance covenants.

9. ASSET RETIREMENT OBLIGATIONS

	December 31, 2021	December 31, 2020
Balance, beginning of year	\$ 760,383	\$ 667,974
Liabilities incurred	14,845	15,189
Liabilities settled	(6,662)	(7,168)
Liabilities acquired from property acquisitions	249	—
Liabilities divested	(3,161)	(721)
Property swaps	(4,113)	(525)
Accretion (note 15)	12,381	8,978
Government grants ⁽¹⁾	(2,857)	(2,128)
Change in estimate	(9,686)	(12,771)
Changes in discount rates and inflation rates ⁽²⁾	(17,381)	92,576
Foreign currency translation	(315)	(1,021)
Balance, end of year	\$ 743,683	\$ 760,383
Less current portion of asset retirement obligations	11,080	11,820
Non-current portion of asset retirement obligations	\$ 732,603	\$ 748,563

(1) During 2021, Baytex recognized \$2.9 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 (\$2.1 million in 2020).

(2) The discount and inflation rates at December 31, 2021 were 1.7% and 1.8% respectively (December 31, 2020 - 1.2% and 1.5%).

At December 31, 2021, the undiscounted amount of estimated cash flows required to settle the asset retirement obligations is \$721.7 million (December 31, 2020 - \$721.0 million). The discounted amount of estimated cash flow required to settle the asset retirement obligations at December 31, 2021, calculated using an estimated inflation rate of 1.8% (December 31, 2020 - 1.5%) and a risk free discount rate of 1.7% (December 31, 2020 - 1.2%), is \$743.7 million (December 31, 2020 - \$760.4 million). These costs are expected to be incurred over the next 60 years.

10. SHAREHOLDERS' CAPITAL

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10.0 million preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. As at December 31, 2021, 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, 2019	558,305	\$ 5,718,835
Vesting of share awards	2,922	10,583
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

11. SHARE-BASED COMPENSATION PLAN

For the year ended December 31, 2021, the Company recorded total compensation expense related to the share awards of \$11.1 million (\$9.5 million for the year ended December 31, 2020) which includes \$4.7 million of compensation expense related to the incentive award plan, deferred share unit plan and the associated equity total return swaps (\$2.3 million for the year ended December 31, 2020).

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 year ended December 31, 2021 was \$1.31 per restricted and performance award (\$1.48 for the year ended December 31, 2020).

The number of share awards outstanding is detailed below:

<i>(000s)</i>	Number of restricted awards	Number of performance awards	Total number of share awards
Balance, December 31, 2019	3,801	3,135	6,936
Granted	2,239	3,253	5,492
Vested and converted to common shares	(1,730)	(1,192)	(2,922)
Forfeited	(188)	(1,108)	(1,296)
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

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 year ended December 31, 2021, Baytex granted 5.0 million awards under the Incentive Award plan at a fair value of \$1.33 per award (2.9 million awards at \$1.50 per award for the year ended December 31, 2020). At December 31, 2021 there were 6.4 million awards outstanding under the Incentive Award plan (2.6 million awards outstanding at December 31, 2020).

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 year ended December 31, 2021, Baytex granted 0.9 million awards under the DSU plan at a fair value of \$1.29 per award. At December 31, 2021, there were 0.8 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 \$6.5 million on December 31, 2021 (December 31, 2020 - liability of \$1.1 million). At December 31, 2021, an asset of \$10.7 million associated with the equity return swap is included in accounts payable as it relates to the settlement of cash compensation payable (December 31, 2020 - a liability of \$1.2 million).

12. NET INCOME (LOSS) PER SHARE

Baytex calculates basic income or loss per share based on the net income or loss attributable to shareholders using the weighted average number of shares outstanding during the period. Diluted income 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 year.

	Years Ended December 31					
	2021			2020		
	Net income	Weighted average common shares (000's)	Net income per share	Net loss	Weighted average common shares (000's)	Net loss per share
Net income (loss) - basic	\$ 1,613,600	563,674	\$ 2.86	\$ (2,438,964)	560,657	\$ (4.35)
Dilutive effect of share awards	—	7,936	—	—	—	—
Net income (loss) - diluted	\$ 1,613,600	571,610	\$ 2.82	\$ (2,438,964)	560,657	\$ (4.35)

For the year ended December 31, 2021, no share awards were excluded from the calculation of diluted income per share as their effect was dilutive. For the year ended December 31, 2020, all share awards were excluded from the calculation of diluted earnings per share as their effect was anti-dilutive given the Company recorded a net loss.

13. PETROLEUM AND NATURAL GAS SALES

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

	Years Ended December 31					
	2021			2020		
	Canada	U.S.	Total	Canada	U.S.	Total
Light oil and condensate	\$ 480,199	\$ 585,635	\$ 1,065,834	\$ 296,125	\$ 327,460	\$ 623,585
Heavy oil	560,696	—	560,696	236,235	—	236,235
NGL	18,904	75,611	94,515	6,037	34,845	40,882
Natural gas sales	68,338	78,812	147,150	33,344	41,431	74,775
Total petroleum and natural gas sales	\$ 1,128,137	\$ 740,058	\$ 1,868,195	\$ 571,741	\$ 403,736	\$ 975,477

Included in accounts receivable at December 31, 2021 is \$154.0 million of accrued receivables related to delivered volumes (December 31, 2020 - \$81.3 million).

14. INCOME TAXES

The provision for income taxes has been computed as follows:

	Years Ended December 31	
	2021	2020
Net income (loss) before income taxes	\$ 1,694,840	\$ (2,599,357)
Expected income taxes at the statutory rate of 25.12% (2020 – 25.42%)	425,744	(660,757)
(Increase) decrease in income tax recovery resulting from:		
Share-based compensation	1,605	1,834
Effect of foreign exchange	(841)	1,017
Effect of change in income tax rates	(65)	10,969
Effect of rate adjustments for foreign jurisdictions	(21,746)	22,375
Effect of change in deferred tax benefit not recognized	(325,295)	444,117
Effect of U.S. tax change	—	19,807
Adjustments and assessments	1,838	245
Income tax expense (recovery)	\$ 81,240	\$ (160,393)

At December 31, 2021, a deferred tax asset of \$145.6 million remains unrecognized due to uncertainty surrounding future commodity prices and future capital gains (December 31, 2020 - \$469.7 million). These deferred income tax assets relate to capital losses of \$237.4 million and non-capital losses of \$461.1 million, which expire from 2033 to 2039.

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

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

As at	January 1, 2021	Recognized in Net Income	Foreign Currency Translation Adjustment	December 31, 2021
Taxable temporary differences:				
Petroleum and natural gas properties	\$ (502,625)	\$ (257,800)	\$ (154)	\$ (760,579)
Financial derivatives	—	—	—	—
Other	(22,377)	624	137	(21,616)
Deductible temporary differences:				
Asset retirement obligations	187,840	(2,436)	(68)	185,336
Financial derivatives	5,410	26,082	—	31,492
Non-capital losses	241,514	104,479	(3,109)	342,884
Finance costs	3,705	49,083	2,239	55,027
Net deferred income tax liability ⁽¹⁾	\$ (86,533)	\$ (79,968)	\$ (955)	\$ (167,456)

(1) Non-capital loss carry-forwards at December 31, 2021 totaled \$2.0 billion and expire from 2033 to 2039.

As at	January 1, 2020	Recognized in Net Loss	Foreign Currency Translation Adjustment	December 31, 2020
Taxable temporary differences:				
Petroleum and natural gas properties	\$ (881,994)	\$ 378,321	\$ 1,048	\$ (502,625)
Financial derivatives	—	—	—	—
Other	(2,403)	(18,839)	(1,135)	(22,377)
Deductible temporary differences:				
Asset retirement obligations	164,523	23,432	(115)	187,840
Financial derivatives	802	4,608	—	5,410
Non-capital losses	386,717	(141,468)	(3,735)	241,514
Finance costs	97,047	(85,087)	(8,255)	3,705
Net deferred income tax liability ⁽¹⁾	\$ (235,308)	\$ 160,967	\$ (12,192)	\$ (86,533)

(1) Non-capital loss carry-forwards at December 31, 2020 totaled \$2.2 billion and expire from 2034 to 2040.

15. FINANCING AND INTEREST

	Years Ended December 31	
	2021	2020
Interest on credit facilities	\$ 13,300	\$ 15,256
Interest on long-term notes	78,546	90,830
Interest on lease obligations	223	448
Cash interest	\$ 92,069	\$ 106,534
Amortization of debt issue costs	4,858	6,617
Accretion of asset retirement obligations (note 9)	12,381	8,978
Early redemption expense (note 8)	1,851	3,312
Financing and interest	\$ 111,159	\$ 125,441

16. FOREIGN EXCHANGE

	Years Ended December 31	
	2021	2020
Unrealized foreign exchange loss - intercompany notes ⁽¹⁾	\$ 12,000	\$ 31,617
Unrealized foreign exchange gain - long-term notes & credit facilities	(13,905)	(22,385)
Realized foreign exchange gain	(963)	(544)
Foreign exchange (gain) loss	\$ (2,868)	\$ 8,688

(1) During 2020, a series of intercompany notes totaling US\$751.0 million were issued from a Canadian subsidiary to a U.S. subsidiary. During 2021, US\$150.0 million of these notes were redeemed and cancelled. At December 31, 2021, US\$601.0 million of this series of intercompany notes remained outstanding. 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 subsidiary are recognized in unrealized foreign exchange gain or loss whereas those within the U.S. subsidiary are recognized in other comprehensive income.

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

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

	December 31, 2021		December 31, 2020		Fair Value Measurement Hierarchy
	Carrying value	Fair value	Carrying value	Fair value	
Financial Assets					
<i>FVTPL</i>					
Financial Derivatives	\$ 8,654	\$ 8,654	\$ 5,057	\$ 5,057	Level 2
Total	\$ 8,654	\$ 8,654	\$ 5,057	\$ 5,057	
<i>Amortized cost</i>					
Trade and other receivables	\$ 173,409	\$ 173,409	\$ 107,477	\$ 107,477	—
Total	\$ 173,409	\$ 173,409	\$ 107,477	\$ 107,477	
Financial Liabilities					
<i>FVTPL</i>					
Financial Derivatives	\$ (134,020)	\$ (134,020)	\$ (26,792)	\$ (26,792)	Level 2
Total	\$ (134,020)	\$ (134,020)	\$ (26,792)	\$ (26,792)	
<i>Amortized cost</i>					
Trade and other payables	\$ (190,692)	\$ (190,692)	\$ (155,955)	\$ (155,955)	—
Credit Facilities	(505,171)	(506,514)	(649,221)	(651,173)	—
Long-term notes	(874,527)	(917,889)	(1,132,868)	(761,129)	Level 1
Total	\$ (1,570,390)	\$ (1,615,095)	\$ (1,938,044)	\$ (1,568,257)	

There were no transfers between Level 1 and Level 2 during the years ended December 31, 2021 or 2020.

Foreign Currency Risk

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

A \$0.01 increase or decrease in the CAD/USD foreign exchange rate on the revaluation of outstanding U.S. dollar denominated assets and liabilities would impact net income or loss before income taxes by approximately \$2.3 million.

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

	Assets		Liabilities	
	December 31, 2021	December 31, 2020	December 31, 2021	December 31, 2020
U.S. dollar denominated	US\$602,503	US\$759,508	US\$829,934	US\$934,731

Interest Rate Risk

The Company's interest rate risk arises from borrowing at floating rates under the Credit Facilities (note 7). Based on the principal outstanding on the Credit Facilities as at December 31, 2021, a change of 100 basis points in interest rates would impact net income or loss before income taxes by approximately \$5.1 million.

Commodity Price Risk

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

When assessing the potential impact of crude oil price changes on the crude oil financial derivative contracts outstanding as at December 31, 2021, a US\$1.00/bbl change in the underlying benchmark crude oil prices would impact net income or loss before income taxes by approximately \$10.4 million.

When assessing the potential impact of natural gas price changes on the financial derivative contracts outstanding as at December 31, 2021, a US\$0.25 change in the underlying benchmark natural gas prices would impact net income or loss before income taxes by approximately \$3.7 million.

Financial Derivative Contracts

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

	Period	Volume	Price/Unit ⁽¹⁾	Index
Oil				
Basis swap	Jan 2022 to Dec 2022	12,000 bbl/d	WTI less US\$12.40/bbl	WCS
Basis swap	Jan 2022 to Dec 2022	4,000 bbl/d	WTI less US\$4.43/bbl	MSW
Basis swap ⁽³⁾	Feb 2022 to Jun 2022	1,000 bbl/d	WTI less US\$3.00/bbl	MSW
Basis swap ⁽³⁾	Mar 2022 to Dec 2022	2,000 bbl/d	WTI less US\$2.88/bbl	MSW
Fixed - Sell	Jan 2022 to Dec 2022	10,000 bbl/d	US\$53.50/bbl	WTI
3-way option ⁽²⁾	Jan 2022 to Dec 2022	1,500 bbl/d	US\$40.00/US\$50.00/US\$58.10	WTI
3-way option ⁽²⁾	Jan 2022 to Dec 2022	2,000 bbl/d	US\$46.00/US\$56.00/US\$66.72	WTI
3-way option ⁽²⁾	Jan 2022 to Dec 2022	2,500 bbl/d	US\$47.00/US\$57.00/US\$67.00	WTI
3-way option ⁽²⁾	Jan 2022 to Dec 2022	2,500 bbl/d	US\$50.00/US\$60.00/US\$70.00	WTI
3-way option ⁽²⁾	Jan 2022 to Dec 2022	2,000 bbl/d	US\$53.00/US\$63.50/US\$72.90	WTI
3-way option ⁽²⁾	Jan 2023 to Dec 2023	2,000 bbl/d	US\$55.00/US\$66.00/US\$84.00	WTI
3-way option ⁽²⁾⁽³⁾	Jan 2023 to Dec 2023	2,500 bbl/d	US\$60.00/US\$75.00/US\$91.54	WTI
Natural Gas				
Fixed - Sell	Jan 2022 to Dec 2022	5,000 GJ/d	\$2.53/GJ	AECO 7A
Fixed - Sell	Jan 2022 to Dec 2022	14,250 GJ/d	\$2.84/GJ	AECO 5A
Fixed - Sell	Jan 2022 to Dec 2022	1,000 mmbtu/d	US\$2.94/mmbtu	NYMEX
3-way option ⁽²⁾	Jan 2022 to Dec 2022	2,500 mmbtu/d	US\$2.25/US\$2.75/US\$3.06	NYMEX
3-way option ⁽²⁾	Jan 2022 to Dec 2022	1,500 mmbtu/d	US\$2.60/US\$2.91/US\$3.56	NYMEX
3-way option ⁽²⁾	Jan 2022 to Dec 2022	2,500 mmbtu/d	US\$2.60/US\$3.00/US\$3.83	NYMEX
3-way option ⁽²⁾	Jan 2022 to Dec 2022	2,500 mmbtu/d	US\$2.65/US\$2.90/US\$3.40	NYMEX
3-way option ⁽²⁾	Jan 2022 to Dec 2022	2,500 mmbtu/d	US\$3.00/US\$3.75/US\$4.40	NYMEX

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

(2) Producer 3-way option consists of a sold call, a bought put and a sold put. To illustrate, in a US\$50.00/US\$60.00/US\$70.00 contract, Baytex receives WTI plus US\$10.00/bbl when WTI is at or below US\$50.00/bbl; Baytex receives US\$60.00/bbl when WTI is between US\$50.00/bbl and US\$60.00/bbl; Baytex receives the market price when WTI is between US\$60.00/bbl and US\$70.00/bbl; and Baytex receives US\$70.00/bbl when WTI is above US\$70.00/bbl.

(3) Contracts entered subsequent to December 31, 2021.

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

	Years Ended December 31	
	2021	2020
Realized financial derivatives loss (gain)	\$ 184,241	\$ (47,836)
Unrealized financial derivatives loss	103,631	18,500
Financial derivatives loss (gain)	\$ 287,872	\$ (29,336)

Liquidity Risk

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

As at December 31, 2021, Baytex had \$506.5 million of principal amounts and \$15.0 million of letters of credit outstanding on its Credit Facilities (December 31, 2020 - \$651.2 million and \$15.0 million, respectively) which have total availability of \$1.0 billion (December 31, 2020 - \$1.0 billion).

The timing of cash outflows relating to financial liabilities as at December 31, 2021 is outlined in the table below:

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	\$ 190,692	\$ 190,692	—	\$ —	\$ —
Financial derivatives	134,020	134,020	—	—	—
Credit facilities ⁽¹⁾⁽²⁾	506,514	—	506,514	—	—
Long-term notes ⁽¹⁾⁽³⁾	885,920	—	253,120	—	632,800
Interest on long-term notes ⁽⁴⁾	325,172	69,608	130,868	110,740	13,956
Lease obligations ⁽¹⁾	8,014	3,068	3,989	902	55
	\$ 2,050,332	\$ 397,388	\$ 894,491	\$ 111,642	\$ 646,811

(1) Principal amount of instruments.

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

(3) Principal amount of instruments. The US\$500 million principal amount of 8.75% senior unsecured notes is due April 1, 2027 and the US\$200 million principal amount of the 5.625% senior unsecured notes is due June 1, 2024 (note 8).

(4) Excludes interest on credit facilities as interest payments on credit facilities fluctuate based on amounts outstanding and the prevailing interest rate at the time of borrowing.

Credit Risk

Credit risk is the risk that a counterparty to a financial asset will default resulting in Baytex incurring a loss. As at December 31, 2021, the Company is exposed to credit risk with respect to its trade and other receivables and financial derivatives. Baytex manages these risks through the selection and monitoring of credit-worthy counterparties.

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

The majority of the Company's credit exposure on trade and other receivables at December 31, 2021 relates to accrued revenues. Accounts receivable from purchasers of the Company's petroleum and natural gas sales are typically collected on the 25th day of the month following production. Joint interest receivables are typically collected within one to three months following production. Included in trade and other receivables at December 31, 2021 is \$154.0 million (December 31, 2020 - \$81.3 million) of accrued receivables related to delivered volumes.

Should the Company determine that the ultimate collection of a receivable is in doubt, the carrying amount of trade and other receivables is reduced by adjusting the allowance for doubtful accounts and recording a charge to net income or loss. If the Company subsequently determines the accounts receivable is uncollectible, the receivable and allowance for doubtful accounts are adjusted accordingly. As at December 31, 2021, allowance for doubtful accounts was \$2.6 million (December 31, 2020 - \$2.0 million).

In determining whether amounts past due are collectible, the Company will assess the nature of the past due amounts as well as the credit worthiness and past payment history of the counterparty. As at December 31, 2021, accounts receivable that Baytex has deemed past due (more than 90 days) but not impaired was \$1.8 million (December 31, 2020 - \$1.6 million). Baytex has estimated the lifetime expected credit loss as at and for the year ended December 31, 2021 to be nominal.

The Company's trade and other receivables, net of the allowance for doubtful accounts, were aged as follows at December 31, 2021.

Trade and Other Receivables Aging	December 31, 2021	December 31, 2020
Current (less than 30 days)	\$ 171,058	\$ 104,210
31-60 days	441	1,493
61-90 days	107	220
Past due (more than 90 days)	1,803	1,554
	\$ 173,409	\$ 107,477

18. SUPPLEMENTAL INFORMATION

Changes in Non-Cash Working Capital Items

	Years Ended December 31	
	2021	2020
Trade and other receivables	\$ (65,932)	\$ 66,285
Trade and other payables	34,737	(51,499)
	\$ (31,195)	\$ 14,786
Changes in non-cash working capital related to:		
Operating activities	\$ (26,582)	\$ 48,758
Investing activities	(2,797)	(32,031)
Foreign currency translation on non-cash working capital	(1,816)	(1,941)
	\$ (31,195)	\$ 14,786

Income Statement Presentation

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

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

	Years Ended December 31	
	2021	2020
Operating	\$ 11,053	\$ 9,065
General and administrative	29,538	22,802
Total employee compensation costs	\$ 40,591	\$ 31,867

19. COMMITMENTS

Baytex has a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact the Company's cash flow from operations in an ongoing manner. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of December 31, 2021, and the expected timing of funding of these obligations, are noted in the table below.

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Processing agreements	\$ 6,090	753	890	530	3,917
Transportation agreements	81,182	20,500	37,825	14,673	8,184
Total	\$ 87,272	\$ 21,253	\$ 38,715	\$ 15,203	\$ 12,101

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

20. RELATED PARTIES

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

	Years Ended December 31	
	2021	2020
Short-term employee benefits	\$ 5,995	\$ 4,295
Share-based compensation	5,917	4,080
Total compensation for key management personnel	\$ 11,912	\$ 8,375

21. CAPITAL MANAGEMENT

The Company's capital management objective is to maintain financial flexibility and sufficient sources of liquidity to execute its capital programs, while meeting short and long-term commitments. Baytex strives to actively manage its capital structure in response to changes in economic conditions. At December 31, 2021, 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 its 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.

	December 31, 2021	December 31, 2020
Credit facilities	\$ 505,171	\$ 649,221
Unamortized debt issuance costs - Credit Facilities (note 7)	1,343	1,952
Long-term notes	874,527	1,132,868
Unamortized debt issuance costs - Long-term notes (note 8)	11,393	15,082
Trade and other payables	190,692	155,955
Trade and other receivables	(173,409)	(107,477)
Net Debt	\$ 1,409,717	\$ 1,847,601

Adjusted Funds Flow

Adjusted Funds Flow is used to monitor operating performance and the Company's ability to generate funds for exploration and development expenditures, debt repayment, settlement of abandonment obligations and potential future dividends. Baytex also uses a Net Debt to Adjusted Funds Flow ratio calculated on a twelve-month trailing basis to monitor the Company's existing capital structure and future liquidity requirements.

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

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

Year-end 2021 Reserves

Baytex's year-end 2021 proved and probable reserves were evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel"), an independent qualified reserves evaluator. All of our oil and gas properties were evaluated in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") using the average commodity price forecasts and inflation rates of McDaniel, GLJ Petroleum Consultants ("GLJ") and Sproule Associates Limited ("Sproule") as of January 1, 2022. Complete reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2021, which will be filed on or before March 31, 2022.

Reserves Highlights

- Proved developed producing ("PDP") reserves increased by 7%, from 120 mmboe to 129 mmboe. Proved reserves ("1P") total 278 mmboe (271 mmboe at year-end 2020) and proved plus probable reserves ("2P") total 451 mmboe (462 mmboe at year-end 2020).
- Finding and development ("F&D") costs, including changes in future development costs ("FDC"), were \$8.20/boe for PDP reserves, \$17.67/boe for 1P reserves and \$24.55/boe for 2P reserves.
- Generated a PDP recycle ratio of 4.5x and a 1P recycle ratio of 2.1x based on 2021 operating netback⁽²⁾ of \$36.52/boe.
- Reserves on a 1P basis are comprised of 80% oil and NGL (36% light oil, 26% NGL's, 17% heavy oil and 2% bitumen) and 20% natural gas. PDP reserves represent 46% of 1P reserves (44% at year-end 2020) and 1P reserves represent 62% of 2P reserves (59% at year-end 2020).
- Baytex maintains a strong reserves life index of 4.4 years based on PDP reserves, 9.4 years based on 1P reserves and 15.3 years based on 2P reserves.
- At year-end, 2021, the present value of our reserves, discounted at 10% before tax, is estimated to be \$5.1 billion (\$3.3 billion at year-end 2020). The increase is largely attributable to a higher commodity price forecast being utilized by our reserves evaluator (consultant average of approximately US\$70/bbl WTI).
- Our net asset value at year-end 2021, discounted at 10% before tax, is \$6.67 per share. This is based on the estimated reserves value plus a value for undeveloped acreage, net of long-term debt and working capital.

(1) Spending includes government grants received for abandonment and reclamations of \$2 million in 2020, \$3 million in 2021 and \$15 million in 2022.

(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.

The following table sets forth our gross and net reserves volumes at December 31, 2021 by product type and reserves category. Please note that the data in the table may not add due to rounding.

Reserves Summary

Reserves Summary	Light and Medium Oil (mbbls)	Tight Oil (mbbls)	Heavy Oil (mbbls)	Bitumen (mbbls)	Total Oil (mbbls)	Natural Gas Liquids ⁽³⁾ (mbbls)	Conventional Natural Gas ⁽⁴⁾ (mmcf)	Shale Gas (mmcf)	Total ⁽⁵⁾ (mboe)
Gross⁽¹⁾									
Proved producing	18,564	26,623	23,735	641	69,564	31,853	65,234	99,778	128,919
Proved developed non-producing	664	314	765	—	1,743	852	1,973	2,448	3,333
Proved undeveloped	26,781	26,278	21,503	4,197	78,759	39,431	37,216	129,213	145,929
Total proved	46,009	53,216	46,003	4,838	150,067	72,137	104,423	231,439	278,181
Total probable	23,296	21,485	29,705	45,874	120,360	27,751	62,394	84,928	172,665
Proved plus probable	69,305	74,701	75,709	50,713	270,427	99,888	166,817	316,367	450,846
Net⁽²⁾									
Proved producing	17,436	19,797	20,775	575	58,583	23,735	58,749	74,461	104,519
Proved developed non-producing	617	232	689	—	1,538	630	1,687	1,812	2,751
Proved undeveloped	24,891	19,882	19,139	3,857	67,769	29,521	34,310	96,601	119,108
Total proved	42,944	39,911	40,602	4,432	127,890	53,885	94,745	172,874	226,378
Total probable	21,399	16,404	25,547	37,186	100,535	20,970	56,747	64,506	141,715
Proved plus probable	64,343	56,315	66,149	41,618	228,425	74,856	151,492	237,381	368,093

Notes:

- (1) "Gross" reserves means the total working interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.
- (2) "Net" reserves means Baytex's gross reserves less all royalties payable to others plus royalty interest reserves.
- (3) Natural Gas Liquids includes condensate.
- (4) Conventional Natural Gas includes associated, non-associated and solution gas.
- (5) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Reserves Reconciliation

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

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

	Light and Medium Oil (mmbbls)	Tight Oil (mmbbls)	Heavy Oil (mmbbls)	Bitumen (mmbbls)	Total Oil (mmbbls)	Natural Gas Liquids ⁽³⁾ (mmbbls)	Conventional Natural Gas ⁽⁴⁾ (mmcf)	Shale Gas (mmcf)	Total ⁽⁵⁾ (mboe)
December 31, 2020	52,067	53,316	35,412	5,737	146,532	72,475	87,894	226,334	271,378
Extensions	3,227	4,370	8,977	—	16,574	4,294	16,032	16,165	26,234
Technical Revisions ⁽²⁾	(6,059)	520	2,949	(394)	(2,984)	(1,379)	(1,649)	1,599	(4,372)
Acquisitions	3	—	1,228	—	1,231	—	—	—	1,231
Dispositions	(2)	(20)	(260)	—	(282)	(19)	(313)	(35)	(360)
Economic Factors	2,509	612	5,160	130	8,411	1,159	20,547	1,995	13,326
Production	(5,734)	(5,581)	(7,464)	(635)	(19,414)	(4,392)	(18,088)	(14,619)	(29,257)
December 31, 2021	46,009	53,216	46,003	4,838	150,067	72,137	104,423	231,439	278,181

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

	Light and Medium Oil (mmbbls)	Tight Oil (mmbbls)	Heavy Oil (mmbbls)	Bitumen (mmbbls)	Total Oil (mmbbls)	Natural Gas Liquids ⁽³⁾ (mmbbls)	Conventional Natural Gas ⁽⁴⁾ (mmcf)	Shale Gas (mmcf)	Total ⁽⁵⁾ (mboe)
December 31, 2020	25,688	24,642	30,544	46,093	126,967	32,760	86,778	96,852	190,332
Extensions	2,413	(2,315)	(760)	—	(663)	(2,989)	(9,810)	(10,055)	(6,963)
Technical Revisions ⁽²⁾	(5,357)	(1,018)	(1,721)	(216)	(8,312)	(1,634)	(70)	(2,403)	(10,359)
Acquisitions	—	—	458	—	458	—	—	—	458
Dispositions	(5)	(5)	(225)	—	(235)	(258)	(7,224)	(9)	(1,699)
Economic Factors	556	182	1,409	(2)	2,145	(127)	(7,280)	543	895
Production	—	—	—	—	—	—	—	—	—
December 31, 2021	23,296	21,485	29,705	45,874	120,360	27,751	62,394	84,928	172,665

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

	Light and Medium Oil (mmbbls)	Tight Oil (mmbbls)	Heavy Oil (mmbbls)	Bitumen (mmbbls)	Total Oil (mmbbls)	Natural Gas Liquids ⁽³⁾ (mmbbls)	Conventional Natural Gas ⁽⁴⁾ (mmcf)	Shale Gas (mmcf)	Total ⁽⁵⁾ (mboe)
December 31, 2020	77,755	77,958	65,956	51,830	273,499	105,235	174,671	323,186	461,710
Extensions	5,640	2,054	8,217	—	15,911	1,304	6,222	6,110	19,271
Technical Revisions ⁽²⁾	(11,416)	(498)	1,228	(610)	(11,296)	(3,013)	(1,719)	(804)	(14,730)
Acquisitions	3	—	1,686	—	1,689	—	—	—	1,689
Dispositions	(7)	(26)	(485)	—	(517)	(278)	(7,536)	(45)	(2,058)
Economic Factors	3,065	794	6,570	127	10,556	1,031	13,267	2,538	14,221
Production	(5,734)	(5,581)	(7,464)	(635)	(19,414)	(4,392)	(18,088)	(14,619)	(29,257)
December 31, 2021	69,305	74,701	75,709	50,713	270,427	99,888	166,817	316,367	450,846

Notes:

- (1) "Gross" reserves means the total working interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.
- (2) Negative revisions in light and medium oil are predominantly associated with our Viking asset and due to variations in performance versus previous forecasts and the removal of inventory locations with higher finding and development costs.
- (3) Natural gas liquids include condensate.
- (4) Conventional natural gas includes associated, non-associated and solution gas.
- (5) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Future Development Costs

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

Future Development Costs (\$ millions)	Proved Reserves	Proved Plus Probable Reserves
2022	416	423
2023	506	540
2024	517	562
2025	489	581
2026	398	657
Remainder	84	987
Total FDC undiscounted	2,410	3,750

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

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

\$ millions except for per boe amounts	2021	2020	2019	3 Year
Proved plus Probable Reserves				
Finding & Development Costs				
Exploration and development expenditures	\$ 313.3	\$ 280.3	\$ 552.3	1,145.9
Net change in Future Development Costs	\$ 147.4	\$ (705.9)	\$ 96.7	(461.8)
Gross Reserves additions (mmboe)	18.8	(38.4)	39.8	20.2
F&D Costs (\$/boe)	\$ 24.55	\$ 11.08	\$ 16.30	33.92
Finding, Development & Acquisition (“FD&A”) Costs				
Exploration and development expenditures and net acquisitions	\$ 307.1	\$ 280.2	\$ 554.5	1,141.7
Net change in Future Development Costs	\$ 144.4	\$ (709.3)	\$ 79.9	(485.0)
Gross Reserves additions (mmboe)	18.4	(38.6)	38.6	18.5
FD&A Costs (\$/boe)	\$ 24.55	\$ 11.12	\$ 16.42	35.59
Proved Reserves				
Finding & Development Costs				
Exploration and development expenditures	\$ 313.3	\$ 280.3	\$ 552.3	1,145.9
Net change in Future Development Costs	\$ 308.6	\$ (464.4)	\$ (90.4)	(246.2)
Gross Reserves additions (mmboe)	35.2	(13.1)	35.8	57.9
F&D Costs (\$/boe)	\$ 17.67	\$ 14.06	\$ 12.92	15.55
Finding, Development & Acquisition Costs				
Exploration and development expenditures and net acquisitions	\$ 307.1	\$ 280.2	\$ 554.5	1,141.7
Net change in Future Development Costs	\$ 316.8	\$ (464.4)	\$ (107.2)	(254.7)
Gross Reserves additions (mmboe)	36.1	(13.1)	34.7	57.7
FD&A Costs (\$/boe)	\$ 17.30	\$ 14.07	\$ 12.88	15.38
Proved Developed Producing Reserves				
Finding & Development Costs				
Exploration and development expenditures	\$ 313.3	\$ 280.3	\$ 552.3	1,145.9
Gross Reserves additions (mmboe)	38.2	7.7	42.5	88.2
F&D Costs (\$/boe)	\$ 8.20	\$ 36.63	\$ 13.04	12.99
Finding, Development & Acquisition Costs				
Exploration and development expenditures and net acquisitions	\$ 307.1	\$ 280.2	\$ 554.5	1,141.7
Gross Reserves additions (mmboe)	38.1	7.6	42.5	88.3
FD&A Costs (\$/boe)	\$ 8.06	\$ 36.64	\$ 13.04	12.93

Reserves Life Index

The following table sets forth our reserves life index, which is calculated by dividing our proved and proved plus probable reserves at year-end 2021 by annualized Q4/2021 production.

	Reserves Life Index (years)		
	Q4/2021 Production	Proved	Proved Plus Probable
Crude Oil and NGL (bbl/d)	66,452	9.2	15.3
Natural Gas (mcf/d)	86,029	10.7	15.4
Oil Equivalent (boe/d)	80,789	9.4	15.3

Forecast Prices and Costs

The following table summarizes the forecast prices used in preparing the estimated reserves volumes and the net present values of future net revenues at December 31, 2021. The estimated future net revenue to be derived from the production of the reserves is based on the following average of the price forecasts of McDaniel, GLJ and Sproule as of January 1, 2022.

Year	WTI Crude Oil US\$/bbl	Edmonton Light Crude Oil \$/bbl	Western Canadian Select \$/bbl	Henry Hub US\$/MMbtu	AECO Spot \$/MMbtu	Inflation Rate %/Yr	Exchange Rate \$US/\$Cdn
2021 act.	67.95	80.25	68.80	3.90	3.55	1.4	0.800
2022	72.83	86.82	74.42	3.85	3.56	—	0.797
2023	68.78	80.73	69.17	3.44	3.21	2.3	0.797
2024	66.76	78.01	66.54	3.17	3.05	2.0	0.797
2025	68.09	79.57	67.87	3.24	3.11	2.0	0.797
2026	69.45	81.16	69.23	3.30	3.17	2.0	0.797
2027	70.84	82.78	70.61	3.37	3.23	2.0	0.797
2028	72.26	84.44	72.02	3.44	3.30	2.0	0.797
2029	73.70	86.13	73.46	3.50	3.36	2.0	0.797
2030	75.18	87.85	74.69	3.58	3.43	2.0	0.797
2031	76.68	89.61	76.19	3.65	3.50	2.0	0.797
Thereafter	Escalation rate of 2.0%					2.0	0.797

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

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

Reserves at December 31, 2021 (\$ millions, discounted at)	0%	5%	10%	15%
Proved developed producing	2,399	2,235	1,988	1,787
Proved developed non-producing	94	72	60	52
Proved undeveloped	2,852	1,948	1,399	1,040
Total proved	5,345	4,255	3,448	2,880
Probable	4,596	2,554	1,636	1,149
Total Proved Plus Probable (before tax)	9,941	6,809	5,084	4,029

Note:

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

Net Asset Value (Forecast Prices and Costs)

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

The following table sets forth our net asset value as at December 31, 2021.

(\$ millions, except per share amounts, discounted at)	5%	10%	15%
Net present value of proved plus probable reserves ⁽¹⁾	6,809	5,084	4,029
Undeveloped land holdings ⁽²⁾	89	89	89
Net Debt ⁽⁴⁾	(1,410)	(1,410)	(1,410)
Net Asset Value	5,488	3,763	2,708
Net Asset Value per Share ⁽³⁾	9.73	6.67	4.80

Notes:

- (1) Includes abandonment, decommissioning and reclamation costs for all producing and non-producing wells and facilities.
- (2) The value of undeveloped land holdings generally represents the estimated replacement cost of our undeveloped land.
- (3) Based on 564.2 million common shares outstanding as at December 31, 2021.
- (4) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.

Additional Information

Our audited consolidated financial statements for the year ended December 31, 2021 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.

Advisory Regarding Forward-Looking Statements

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

Specifically, this press release contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; that we expect to generate more than \$550 million of free cash flow in 2022 and reach our \$1.2 billion net debt target in Q2/2022; the next phase of our return of capital framework, which includes allocating 25% of free cash flow to share buy backs starting in Q2/2022; in 2022 that we expect to benefit from our diversified oil weighted portfolio and a commitment to allocate capital effectively and our program is designed to generate stable production while scaling up development in the Clearwater; our 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; we expect to allocate 25% of free cash flow to share buy backs starting in Q2/2022 with the remainder of our free cash flow allocated to debt repayment until we achieve a net debt level of \$800 million, our expected net debt to EBITDA ratios at such net debt level at \$US55 WTI and \$US75 WTI and our expectation that we will achieve that net debt level by mid-2023 at which point we will consider enhanced shareholder returns; in the Eagle Ford that we expect to bring 14 net wells onstream in 2022; in the Viking that we expect to bring 145 net wells onstream in 2022; in 2022, that we will drill ~9 net Bluesky wells at Peace River and 37 net wells at Lloydminster; we have 125 sections that are highly prospective for Clearwater development; we have a follow-up Clearwater well scheduled on our legacy Seal lands in H2/2022; we are drilling 10 wells in Q1/2022 on our Peavine lands and expect to bring 18 wells onstream in 2022; our Clearwater play holds the potential for greater than 200 locations, has strong economics and the ability to grow organically while enhancing free cash flow; in Duvernay that we are drilling a three well pad expected to be onstream in Q3/2022; that we use financial derivative contracts and crude-by-rail to reduce adjusted funds flow volatility, the percentage of our expected production in 2022 of Canadian light oil and heavy oil for which we have hedged the differential to WTI and the percentage of our 2022 and 2023 net crude exposure that is hedged; that we are committed to monitoring GHG emissions, setting targets and pursuing cost-effective

decarbonization strategies; our 2025 GHG emissions intensity reduction target and our strategies to reach the target; our 2022 expected spending on GHG mitigation; our commitment to abandon and reclaim 4,500 wells by 2040, the number of wells we expect to abandon and our expected 2022 spending on abandonment and reclamation; future development costs, F&D and FD&A; our reserves life index; forecast prices for oil and natural gas; forecast inflation and exchange rates; the net present value before income taxes of the future net revenue attributable to our reserves; the value of our undeveloped land holdings and our estimated net asset value. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that they can be profitably produced in the future.

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

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

These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2021, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission not later than March 31, 2022 and in our other public filings.

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

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

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

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.

	Years Ended December 31	
(\$ thousands)	2021	2020
Petroleum and natural gas sales	\$ 1,868,195	\$ 975,477
Blending and other expense	(85,689)	(48,381)
Total sales, net of blending and other expense	1,782,506	927,096
Royalties	(339,156)	(163,735)
Operating expense	(343,002)	(331,345)
Transportation expense	(32,261)	(28,437)
Operating netback	1,068,087	403,579

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.

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

Non-GAAP Financial Ratios

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

(1) Unamortized debt issuance costs were obtained from Note 7 Credit Facilities and Note 8 Long-term Notes from the Consolidated Financial Statements for the year ended December 31, 2021.

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.

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

Advisory Regarding Oil and Gas Information

The reserves information contained in this press release has been prepared in accordance with NI 51-101. Complete NI 51-101 reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2021, which will be filed on or before March 31, 2022. Listed below are cautionary statements that are specifically required by NI 51-101:

- The term barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one boe (6 mcf/bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.
- With respect to finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.
- This press release contains estimates of the net present value of our future net revenue from our reserves. Such amounts do not represent the fair market value of our reserves.

Throughout this press release, "oil and NGL" refers to heavy oil, bitumen, light and medium oil, tight oil, condensate and natural gas liquids ("NGL") product types as defined by NI 51-101. The following table shows Baytex's disaggregated production volumes for the three and twelve months ended December 31, 2021. The NI 51-101 product types are included as follows: "Heavy Oil" - heavy oil and bitumen, "Light and Medium Oil" - light and medium oil, tight oil and condensate, "NGL" - natural gas liquids and "Natural Gas" - shale gas and conventional natural gas.

	Three Months Ended December 31, 2021					Twelve Months Ended December 31, 2021				
	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada – Heavy										
Peace River	11,491	8	22	11,027	13,359	11,198	7	23	11,408	13,130
Lloydminster	10,566	12	—	1,677	10,858	10,202	6	—	1,448	10,449
Peavine	1,425	—	—	—	1,425	788	—	—	—	788
Canada - Light										
Viking	—	14,200	166	11,679	16,313	—	15,277	146	11,133	17,278
Duvernay	—	1,475	733	2,766	2,668	—	1,047	598	2,178	2,008
Remaining Properties	—	693	792	25,524	5,739	—	606	904	25,566	5,771
United States										
Eagle Ford	—	18,598	6,271	33,356	30,428	—	18,846	5,573	37,874	30,731
Total	23,482	34,986	7,984	86,029	80,789	22,188	35,789	7,244	89,606	80,156

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

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

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

Net asset value has been calculated based on the estimated net present value of all future net revenue from our reserves, before income taxes, as estimated by McDaniel effective December 31, 2021, plus the estimated value of our undeveloped land holdings, less net debt.

Reserve life index means the reserves for the particular reserve category divided by annualized 2021 fourth quarter production.

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.

Notice to United States Readers

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

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

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

ABBREVIATIONS

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

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

CORPORATE INFORMATION

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Director

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

AUDITORS

KPMG LLP

RESERVES ENGINEERS

McDaniel & Associates Consultants Ltd.

TRANSFER AGENT

Odyssey Trust Company

EXCHANGE LISTINGS

Toronto Stock Exchange
Symbol: **BTE**

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
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