UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 40-F

☐ **Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934**

☒ **Annual Report pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended: December 31, 2021
Commission File Number: 001-32754

BAYTEX ENERGY CORP.
(Exact name of Registrant as specified in its charter)

Alberta	**1381**	**Not Applicable**
(Province or other jurisdiction of incorporation or organization)	(Primary standard industrial classification code number, if applicable)	(I.R.S. employer identification number, if applicable)

2800, 520 - 3rd Avenue S.W.
Calgary, Alberta
T2P 0R3
(587) 952-3000
(Address and telephone number of registrant's principle executive offices)

Capitol Corporate Services, Inc.
206 E. 9th St., Ste 1300
Austin, Texas 78701
(800) 345-4647
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered pursuant to Section 12(b) of the Act:
Title of each class: Trading Symbol(s): Name of each exchange on which registered:

Securities registered pursuant to Section 12(g) of the Act:
Common Shares

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:
NONE

For annual reports, indicate by check mark the information filed with this form:
☒ Annual Information Form ☒ Audited Annual Financial Statements

Indicate the number of outstanding shares of the issuer's classes of capital or common stock as of the close of the period covered by the annual report: 564,213,044

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes ý No ¨

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit such files).

Yes ý No ¨

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act. ☐ Emerging growth company

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange Act. ☐

† The term “new or revised financial accounting standard” refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.

Indicate by check mark whether the registrant has filed a report on and attestation to its management’s assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ý

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this Annual Report on Form 40-F are forward-looking statements within the meaning of Section 21E of the Securities and Exchange Act of 1934, as amended (the "Exchange Act") and Section 27A of the Securities Act of 1933, as amended. Please see section titled "Special Note Regarding Forward-Looking Statements" in the Annual Information Form, which is Exhibit 99.1 of this Annual Report on Form 40-F.

Principal Documents

The following documents are filed as part of this Annual Report on Form 40-F:

A. Annual Information Form

For the Registrant's Annual Information Form for the year ended December 31, 2021, see Exhibit 99.1 of this Annual Report on Form 40-F.

B. Audited Annual Financial Statements

For the Registrant's Audited Consolidated Financial Statements for the year ended December 31, 2021, including the report of its Independent Registered Public Accounting Firm with respect thereto, see Exhibit 99.2 of this Annual Report on Form 40-F.

C. Management's Discussion and Analysis

For the Registrant's Management's Discussion and Analysis of the operating and financial results for the year ended December 31, 2021, see Exhibit 99.3 of this Annual Report on Form 40-F.

Controls and Procedures

A. Certifications

The required disclosure is included in Exhibits 99.4, 99.5, 99.6 and 99.7 of this Annual Report on Form 40-F.

B. Disclosure Controls and Procedures

As of the end of the Registrant's fiscal year ended December 31, 2021, an internal evaluation was conducted under the supervision of and with the participation of the Registrant's management, including the President and Chief Executive Officer and the Executive Vice President and Chief Financial Officer, of the effectiveness of the design and operation of the Registrant's "disclosure controls and procedures" (as defined in Rule 13a-15(e) under Exchange Act). Based on that evaluation, the President and Chief Executive Officer and the Executive Vice President and Chief Financial Officer concluded that the design and operation of the Registrant's disclosure controls and procedures were effective to ensure that the information required to be disclosed in the reports that the Registrant files or submits to the Securities and Exchange Commission is (i) recorded, processed, summarized and reported, within the required time periods; and (ii) accumulated and communicated to the Registrant's management, including the President and Chief Executive Officer and the Executive Vice President and Chief Financial Officer, to allow timely decisions regarding the required disclosure.

It should be noted that while the President and Chief Executive Officer and the Executive Vice President and Chief Financial Officer believe that the Registrant's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the Registrant's 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.

C. Management's Annual Report on Internal Control Over Financial Reporting

Management's Annual Report on Internal Control Over Financial Reporting is included in the Management's Report that accompanies the Registrant's Audited Consolidated Financial Statements for the year ended December 31, 2021, filed as Exhibit 99.2 to this Annual Report on Form 40-F, and is incorporated herein by reference.

D. Attestation Report of Independent Registered Public Accounting Firm

The Attestation Report of the Registrant's Auditor is included in the Report of Independent Registered Public Accounting Firm that accompanies the Registrant's Audited Consolidated Financial Statements for the year ended December 31, 2021, filed as Exhibit 99.2 of this Annual Report on Form 40-F, and is incorporated herein by reference.

E. Changes in Internal Control Over Financial Reporting

During the year ended December 31, 2021, there were no changes in the Registrant's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Registrant's internal control over financial reporting.

Audit Committee Financial Expert

The Registrant's Board of Directors has determined that Ms. Jennifer Maki and Mr. Gregory Melchin are "audit committee financial experts" (as that term is defined in paragraph 8(b) of General Instruction B to Form 40-F) and are "independent" (as defined by the New York Stock Exchange corporate governance rules).

The Securities and Exchange Commission has indicated that the designation or identification of a person as an “audit committee financial expert” does not (i) mean that such person is an “expert” for any purpose, including without limitation for purposes of Section 11 of the Securities Act of 1933, (ii) impose on such person any duties, obligations or liability that are greater than the duties, obligations and liability imposed on such person as a member of the audit committee and the board of directors in the absence of such designation or identification, or (iii) affect the duties, obligations or liability of any other member of the audit committee or the board of directors.

Code of Ethics

The Registrant has adopted a "code of ethics" (as that term is defined in paragraph 9(b) of General Instruction B to Form 40-F) ("Code of Ethics"), which is applicable to the directors, officers, employees and consultants of the Registrant and its affiliates (including, its principal executive officer, principal financial officer, principal accounting officer or controller, and persons performing similar functions). The Code of Ethics is available on the Registrant's website at www.baytexenergy.com.

In the past fiscal year, the Registrant has not amended any provision of its Code of Ethics that relates to any element of the code of ethics definition enumerated in paragraph (9)(b) of General Instruction B to Form 40-F, or granted any waiver, including an implicit waiver, from any provision of its Code of Ethics.

If any amendment to the Code of Ethics is made, or if any waiver from the provisions thereof is granted, the Registrant may elect to disclose the information about such amendment or waiver required by Form 40-F to be disclosed, by posting such disclosure on the Registrant’s website, which may be accessed at www.batyexenergy.com.

Principal Accountant Fees and Services

The required disclosure is included under the heading "Audit Committee Information - External Auditor Service Fees" in the Registrant's Annual Information Form for the year ended December 31, 2021, filed as Exhibit 99.1 to this Annual Report on Form 40-F, and is incorporated herein by reference. Our independent registered public accounting firm is KPMG LLP, Calgary, Alberta, Canada, Auditor Firm ID: 85.

Off-Balance Sheet Arrangements

The Registrant does not have any "off-balance sheet arrangements" (as that term is defined in paragraph 11(ii) of General Instruction B to Form 40-F) that have or are reasonably likely to have a current or future effect on its financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Cash Obligations

The required disclosure is included under the heading "Capital Resources and Liquidity" and subheading "Capital Resources - Contractual Obligations" in the Registrant's Management's Discussion and Analysis for the year ended December 31, 2021, filed as Exhibit 99.3 to this Annual Report on Form 40-F, and is incorporated herein by reference.

Identification of the Audit Committee

The Registrant has a separately designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Exchange Act. The Registrant's Audit Committee members consist of Ms. J. Maki , Mr. G. Melchin and Mr. D. Hrap.

UNDERTAKING

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

CONSENT TO SERVICE OF PROCESS

(1) The Registrant has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

(2) Any change to the name or address of the Registrant's agent for service shall be communicated promptly to the Commission by amendment to Form F-X referencing the file number of the Registrant.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this report to be signed on its behalf by the undersigned, thereto duly authorized on March 1, 2022.

BAYTEX ENERGY CORP.

By: /s/ *Rodney D. Gray*
Name: Rodney D. Gray
Title: Executive Vice President and Chief Financial Officer

EXHIBIT INDEX

Exhibit No.	Document
99.1	Annual Information Form of the Registrant for the fiscal year ended December 31, 2021.
99.2	Audited Consolidated Financial Statements of the Registrant for the year ended December 31, 2021 together with the Auditors' Report thereon.
99.3	Management's Discussion and Analysis of the operating and financial results of the Registrant for the year ended December 31, 2021.
99.4	Certification of Chief Executive Officer under Section 302 of the *Sarbanes-Oxley Act of 2002.*
99.5	Certification of Chief Financial Officer under Section 302 of the *Sarbanes-Oxley Act of 2002.*
99.6	Certification of Chief Executive Officer under Section 906 of the *Sarbanes-Oxley Act of 2002.*
99.7	Certification of Chief Financial Officer under Section 906 of the *Sarbanes-Oxley Act of 2002.*
99.8	Consent of KPMG LLP, Independent Registered Public Accounting Firm.
99.9	Consent of McDaniel & Associates Consultants Ltd., independent engineers.
99.10	Supplemental Disclosures about Extractive Activities - Oil and Gas (unaudited).
101	Interactive Data File.

Exhibit 99.1



ANNUAL INFORMATION FORM

2021

March 1, 2022

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APPENDICES:

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APPENDIX B REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

APPENDIX C AUDIT COMMITTEE MANDATE AND TERMS OF REFERENCE

SELECTED TERMS

Capitalized terms in this document have the meanings set forth below:

Entities

Baytex or the **Corporation** means Baytex Energy Corp., a corporation incorporated under the ABCA.

Baytex Energy means Baytex Energy Ltd., a corporation amalgamated under the ABCA.

Baytex Partnership means Baytex Energy Limited Partnership, a limited partnership, the partners of which are Baytex Energy and Baytex Energy (LP) Ltd.

Baytex USA means Baytex Energy USA, Inc., a corporation organized under the laws of the State of Delaware.

Board or **Board of Directors** means the board of directors of Baytex.

NYSE means New York Stock Exchange.

OPEC means the Organization of the Petroleum Exporting Countries.

OPEC+ means OPEC plus a number of other oil exporting countries, including Russia.

Raging River means Raging River Exploration Inc.

SEC means the United States Securities and Exchange Commission.

Shareholders mean the holders from time to time of Common Shares.

subsidiary has the meaning ascribed thereto in the *Securities Act* (Ontario) and, for greater certainty, includes all corporations, partnerships and trusts owned, controlled or directed, directly or indirectly, by us.

TSX means the Toronto Stock Exchange.

we, **us** and **our** means Baytex and all its subsidiaries on a consolidated basis unless the context requires otherwise.

Securities and Other Terms

2014 Debt Indenture means the indenture, as amended, among Baytex, as issuer, certain of its subsidiaries, as guarantors, and Computershare Trust Company, N.A., as indenture trustee, dated June 6, 2014.

2020 Debt Indenture means the indenture among Baytex, as issuer, certain of its subsidiaries, as guarantors, and Computershare Trust Company, N.A., as indenture trustee, dated February 5, 2020.

2021 Debentures means the 6.75% series B senior unsecured debentures due February 17, 2021 which were redeemed as of September 13, 2019.

2022 Debentures means the 6.625% series C senior unsecured debentures due July 19, 2022 which were redeemed as of March 5, 2020.

2021 Notes means the 5.125% senior unsecured notes due June 1, 2021 issued by Baytex pursuant to the 2014 Debt Indenture which were redeemed as of February 20, 2020.

2024 Notes means the 5.625% senior unsecured notes due June 1, 2024 issued by Baytex pursuant to the 2014 Debt Indenture.

2027 Notes means the 8.750% senior unsecured notes due April 1, 2027 issued by Baytex pursuant to the 2020 Debt Indenture.

ABCA means the *Business Corporations Act* (Alberta), R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder.

AIF means this annual information form of the Corporation dated March 1, 2022 for the year ended December 31, 2021.

Canadian GAAP means generally accepted accounting principles in Canada, which are consistent with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Common Shares means the common shares of Baytex.

Credit Facilities means our Revolving Credit Facilities and our Term Loan.

CSS means cyclic steam stimulation.

GHG means greenhouse gas.

MD&A means management's discussion and analysis of operating and financial results .

Revolving Credit Facilities means our US$575 million secured covenant-based credit facilities with a syndicate of financial institutions.

SAGD means steam-assisted gravity drainage.

Senior Notes means the 2024 Notes and the 2027 Notes.

Tax Act means the *Income Tax Act* (Canada), R.S.C. 1985, c. 1 (5th Supp.), as amended, including the regulations promulgated thereunder, as amended from time to time.

Term Loan means our $300 million secured term loan with a syndicate of financial institutions.

Independent Engineering

Baytex Reserves Report means the report of McDaniel dated February 3, 2022 entitled "Baytex Energy Corp., Evaluation of Petroleum Reserves, Based on Forecast Prices and Costs, As of December 31, 2021".

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time.

McDaniel means McDaniel & Associates Consultants Ltd., independent petroleum consultants.

NI 51-101 means National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" of the Canadian Securities Administrators.

Reserves Definitions

Gross means:

(a) in relation to our interest in production and reserves, our interest (operating and non-operating) share before deduction of royalties and without including any of our royalty interests;

(b) in relation to wells, the total number of wells in which we have an interest; and

(c) in relation to properties, the total area of properties in which we have an interest.

Net means:

(a) in relation to our interest in production and reserves, our interest (operating and non-operating) share after deduction of royalty obligations, plus our royalty interest in production or reserves;

(b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and

(c) in relation to our interest in a property, the total area in which we have an interest multiplied by our working interest.

Forecast Prices and Costs are prices and costs that are:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which Baytex is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

Reserves and Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

(a) analysis of drilling, geological, geophysical and engineering data;

(b) the use of established technology; and

(c) specified economic conditions (being the Forecast Prices and Costs used in the estimate).

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(i) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(ii) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Development and Production Status

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories:

(a) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into the following categories:

i. **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

ii. **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved or probable) to which they are assigned.

ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrel
Mbbl	thousand barrels
MMbbl	million barrels
NGL	natural gas liquids
bbl/d	barrels per day

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
m^3	cubic metres
MMbtu	million British Thermal Units

Other

API	the measure of the density or gravity of liquid petroleum products as compared to water
BOE or boe	barrel of oil equivalent, using the conversion factor of six Mcf of natural gas being equivalent to one bbl of oil**BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 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.**
boe/d	barrels of oil equivalent per day
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
NYMEX	the New York Mercantile Exchange
AECO	the natural gas storage facility located at Suffield, Alberta

MEH	Magellan East Houston
MSW	Mixed Sweet Blend
WTI	West Texas Intermediate
WCS	Western Canadian Select
$ Million	millions of dollars
$000s	thousands of dollars

CONVERSIONS AND CONVENTIONS

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbl	Cubic metres	0.159
Cubic metres	Bbl	6.293
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.400
Hectares	Acres	2.500

Certain terms used herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings in this AIF as in NI 51-101. Unless otherwise indicated, references in this AIF to "$" or "dollars" are to Canadian dollars and references to "US$" are to United States dollars. All financial information contained in this AIF has been presented in Canadian dollars in accordance with Canadian GAAP. All operational information contained in this AIF relates to our consolidated operations unless the context otherwise requires.

SPECIAL NOTES TO READER

Forward-Looking Statements

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

Specifically, this AIF contains forward-looking statements relating to, but not limited to: our business strategies, plans and objectives; our 2022 guidance for exploration and development expenditures and production; our five-year outlook including expected production, production growth and annual capital spending; our goal of building value by developing our assets and completing selective acquisitions; that we are competitive with similarly situated companies; that we do not expect to be materially affected by the renegotiation or termination of contracts in 2022; development plans for our properties; undeveloped lease expiries; when we expect to pay material income taxes; our working interest production volume for 2022 based on the future net revenue disclosed in our reserves; that we market our production with attention to maximizing value and counterparty performance; the development plans for our undeveloped reserves; our future abandonment and reclamation liabilities; our funding sources for development capital expenditures; the impact of existing and proposed governmental and environmental regulation; and our assessment of our tax filing position for the years 2011 through 2015.

In addition, there are forward-looking statements in this AIF under the headings " *General Description of Our Business*" and "*Statement of Reserves Data*" as to our reserves, including with respect thereto, the future net revenues from our reserves, pricing and inflation rates, future development costs, the development of our proved undeveloped reserves and probable undeveloped reserves, future development costs, reclamation and abandonment obligations, tax horizon, exploration and development activities and production estimates.

These forward-looking statements are based on certain key assumptions regarding, among other things: oil 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.

Readers are cautioned that the foregoing list of risk factors is not exhaustive. New risk factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements. Readers should also carefully consider the matters discussed under the heading "*Risk Factors*" in this AIF.

The above summary of assumptions and risks related to forward-looking statements in this AIF has been provided in order to provide Shareholders and potential investors with a more complete perspective on our current and future operations and such information may not be appropriate for other purposes. There is no representation by us that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and we do 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. The forward-looking statements contained in this AIF are expressly qualified by this cautionary statement.

Access to Documents

Any document referred to in this AIF and described as being accessible on the SEDAR website at *www.sedar.com* or on EDGAR at *www.sec.gov* (including those documents referred to as being incorporated by reference in this AIF) may be obtained free of charge from us at Suite 2800, Centennial Place, East Tower, 520 - 3rd Avenue S.W., Calgary, Alberta, Canada, T2P 0R3.

CORPORATE STRUCTURE

General

Baytex Energy Corp. was incorporated on October 22, 2010 pursuant to the provisions of the ABCA. Baytex is the successor to the business of Baytex Energy Trust, which was transitioned to Baytex on December 31, 2010.

Our head and principal office is located at Suite 2800, Centennial Place, East Tower, 520 – 3 rd Avenue S.W., Calgary, Alberta, Canada, T2P 0R3. Our registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta, Canada, T2P 1G1.

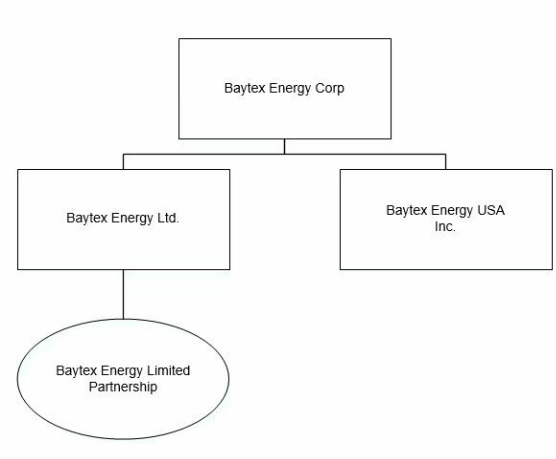
Inter-Corporate Relationships

The following table provides the name, the percentage of voting securities owned by us and the jurisdiction of incorporation, continuance, formation or organization of our material subsidiaries either, direct and indirect, as at the date hereof.

	Percentage of voting securities (directly or indirectly)	Jurisdiction of Incorporation/ Formation
Baytex Energy Ltd.	100%	Alberta
Baytex Energy USA, Inc.	100%	Delaware
Baytex Energy Limited Partnership	100%	Alberta

Our Organizational Structure

The following simplified diagram shows the inter-corporate relationships among us and our material subsidiaries as of the date hereof.



DEVELOPMENT OF OUR BUSINESS

Developments in the Past Three Years

2019

In 2019 commodity prices decreased relative to 2018, with the WTI price averaging US$57.03/bbl for the year as compared to US$64.77 in 2018. The decrease in WTI was partially offset by a narrowing of differentials in Canada, with the WCS differential averaging US$12.75/bbl in 2019 as compared to US$26.31/bbl in 2018, which positively impacted our Canadian operations.

Our production averaged 97,680 boe/d in 2019, above our guidance range and an increase from 2018, due to the contribution from the Raging River assets which were acquired in 2018 and strong well performance, while exploration and development expenditures were at the low end of our budget range for the year at $552 million. In September 2019 we early redeemed US$150 million principal amount of senior unsecured notes due February 2021.

On December 4, we announced a 2020 exploration and development expenditures range of $500-$575 million designed to generate average annual production of 93,000-97,000 boe/d and the appointment of Mark R. Bly as Chair of the Board.

2020

2020 was an extremely challenging year. The spread of Covid-19 and the associated decrease in demand for crude oil combined with a decision by the members of OPEC to increase the supply of crude oil resulted in a significant reduction in commodity prices. Commodity prices increased from their lows following a production curtailment agreement between members of the OPEC+ group to limit supply, but remained below their previous levels as a result of decreased demand associated with continued efforts to limit the spread of Covid-19. The price for WTI averaged US$39.40/bbl for the year.

Prior to the market dislocations caused by the spread of Covid-19 we entered into a series of transactions to extend the maturity dates of our outstanding indebtedness. On February 5, we issued US$500 million principal amount of 2027 Notes. The proceeds of this issuance, along with available cash and liquidity available under our Credit Facilities, were used to redeem our US$400 million principal amount 2021 Notes on February 2020 and our $300 million principal amount 2022 Debentures on March 5, 2020. In addition, on March 2, 2020 we extended the maturity of our Credit Facilities to April 2, 2024. Following these transactions the nearest maturity date of our senior unsecured debt and Credit Facilities was extended from 2021 to 2024.

In response to decreased commodity prices, we took decisive steps to adjust our business model. We reduced our capital budget by 50% and shut-in approximately 25,000 boe/d of production for a portion of the year. As a result, production for the year averaged 79,781 boe/d, while exploration and development expenditures were $280 million.

On December 2 we announced a 2021 exploration and development expenditures range of $220-275 million designed to generate average annual production of 73,000-77,000 boe/d, which reflects the re-set of our business that occurred in 2020.

NYSE Delisting
On March 24, 2020, we received a continued listing standards notice from the NYSE as the average closing price for our Common Shares was less than US$1.00 per share over a period of 30 consecutive trading days. Subsequently, on December 3, 2020, our Common Shares were delisted from the NYSE. Baytex's Common Shares continue to trade on the TSX.

2021

2021 saw significant improvement in commodity markets. Demand for oil and gas recovered from the impacts of the Covid-19 pandemic and supply increases were limited as a result of the agreement between the OPEC+ group to limit production and the capital discipline of North American shale producers who did not pursue significant production growth. The price for WTI averaged US$67.92/bbl for the year.

In April of 2021 we announced an exciting exploration discovery in the Clearwater oil play in Peace River along with a five-year outlook (2021-2025) that highlights our financial and operational sustainability and meaningful free cash flow generation capability. As a result of improved commodity prices and the additional activity at our Clearwater discovery, both our annual production guidance and capital budget were increased. Production for the year averaged 80,156 boe/d and exploration and development expenditures were $313 million. During the year our net debt[(1)] was reduced by $438 million to $1.4 billion and in connection with this debt reduction we repurchased and early redeemed US$200 million principal amount of senior unsecured notes due June 2024.

On December 1 we announced a 2022 exploration and development expenditures range of $400-450 million designed to generate average annual production of 80,000-83,000 boe/d. We also announced an update to our five-year outlook that optimizes production in the 85,000 to 90,000 boe/d range and generates annual production growth of 2% to 4% with annual capital spending of $400 to $475 million from 2022 to 2025.

(1) Capital management measure. Refer to the Specified Financial Measures section in the Annual 2021 MD&A for disclosure regarding this measure. The 2021 MD&A is available on SEDAR at www.sedar.com.

DESCRIPTION OF OUR BUSINESS

Overview

We are engaged in the acquisition, development and production of crude oil and natural gas in the Western Canadian Sedimentary Basin and the Eagle Ford in the United States. Approximately 82% of our

production is weighted toward crude oil and NGLs. The Company and its predecessors have been in business for more than 25 years and our operating teams are well established with a track record of technical proficiency and operational success. Throughout our history we have endeavoured to add value by developing our assets and completing selective acquisitions.

Competitive Conditions

Baytex is a member of the oil and natural gas industry, which is highly competitive. Baytex competes with other companies for all of its business inputs, including development prospects, access to commodity markets, acquisition opportunities, available capital and staffing. We believe our competitive position is, on the whole, similar to that of other oil and natural gas producers of a similar size and production profile. See *Industry Conditions* and *Risk Factors.*

Environmental and Social Policies

We have an active program to monitor and comply with all environmental laws, rules and regulations applicable to our operations. Our policies require that all employees and contractors report all breaches or potential breaches of environmental laws, rules and regulations to our senior management and all applicable governmental authorities. Any material breaches of environmental law, rules and regulations must be reported to the Board of Directors. Our Health, Safety and Environment policy is available on our website at www.baytexenergy.com.

In recognition of the importance of our health, safety and environment policy and targets, including our GHG reduction target, the reserves and sustainability committee of our board of directors has been given specific responsibility for the "oversight and monitoring of the Corporation's performance related to health, safety, environment, climate and other sustainability matters." This change was recognized by amending the committee's mandate and terms of reference in July of 2020.

We have published a Corporate Responsibility Report every second year since 2012 and published our fifth report in June of 2021. This report details our efforts and performance with respect to people, the environment, our community and stakeholders, and responsible business practices. Over this time period our reporting standards and objectives have developed significantly. Some of the highlights from our most recent report are as follows:

- Reduced our corporate GHG intensity by 46% from our 2018 baseline, exceeding our 30% target.
- Reduced our annual reportable spill volumes by 59% in the past five years.
- Reduced our recordable injury rate by 25% in the past five years.
- Established a 2020 fresh water use baseline.
- Initiated our emergency response protocols to address the pandemic and protect the safety of our people.
- Provided Indigenous awareness training for our executive team, senior leaders, and other employees who work with Indigenous communities.
- Signed an economic development agreement with the Peavine Métis Settlement in January 2020.
- Spent $10.3 million procuring goods and services from Indigenous business and paying royalties to First Nations and Métis communities in 2020.
- Completed a period of significant Board renewal to ensure independence and to increase diversity.
- Realigned our pay-for-performance to reflect additional financial and sustainability metrics that will drive the long-term success of our company.
- Established our Environmental Sustainability Team, a cross-functional group that plays a key role in enhancing our environmental performance, managing regulatory change, and improving our reporting.

The disclosure in our most recent report was guided by three reporting frameworks: the Sustainability Accounting Standards Board (SASB), the Global Reporting Initiative (GRI) and the Task Force on Climate-related Financial Disclosures (TCFD). See *Industry Conditions* and *Risk Factors.*

Cyclical and Seasonal Factors

Our operational results and financial condition are dependent on the prices received for our oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years. Such prices are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on our financial condition. We mitigate such price risk by closely monitoring commodity markets, implementing our risk management programs and by maintaining financial liquidity. Additionally, we continually review our capital program and implement initiatives to adapt to such price changes. See *Industry Conditions* and *Risk Factors.*

The level of activity in the oil and gas industry is dependent on access to areas where operations are conducted. In Canada, seasonal weather variations, including spring break-up which occurs annually, affects access in certain circumstances. In Canada and the United States, unexpected adverse weather conditions, such as flooding, extreme cold weather, heavy snowfall, heavy rainfall and forest fires may restrict the Corporation's ability to access its properties. See *Industry Conditions* and *Risk Factors.*

Renegotiation or Termination of Contracts

As at the date hereof, we do not anticipate that any aspects of our business will be materially affected during the remainder of 2022 by the renegotiation or termination of contracts.

Personnel

As at December 31, 2021, we had 148 employees in our head office and 60 employees in our field operations.

PRINCIPAL PROPERTIES

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2021. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2021 and production information represents average working interest production for the year ended December 31, 2021.

Eagle Ford - Texas

Our Eagle Ford assets are located in the core of the liquids-rich Eagle Ford shale in South Texas. Our assets include non-operated working interests in approximately 78,212 (19,931 net) acres, comprised of four areas of mutual interest (Sugarloaf, Longhorn, Ipanema and Excelsior) with an average working interest of approximately 25%, together with field infrastructure and related assets. Our entire acreage position in the Eagle Ford is held by production and the assets are operated by an operating subsidiary of Marathon Oil Corporation (NYSE: MRO), pursuant to the terms of industry-standard joint operating agreements. Production in the area occurs from the hydraulic fracturing of horizontal wells.

During 2021, production from the Eagle Ford assets averaged approximately 30,731 boe/d, comprised of 24,419 bbl/d of light oil, condensate and NGL and 37,874 Mcf/d of shale gas. During this period, Baytex participated in the completion of 93 (23.1 net) wells, resulting in 79 (18.7 net) oil wells and 14 (4.4 net) natural gas wells. As at December 31, 2021, our proved plus probable reserves were 201 million boe (150 million proved; 51 million probable).

Viking - Alberta and Saskatchewan

Our Viking assets are located in the greater Dodsland area in southwest Saskatchewan and in the Esther area of southeastern Alberta. These assets were acquired through a business combination with Raging River in 2018 and produce light oil from the Viking formation. Production in the area occurs primarily from the hydraulic fracturing of horizontal wells. In some areas, reservoirs are placed under waterflood. In 2021, the Viking assets produced 17,278 boe/d, comprised of 15,422 bbl/d of light oil and NGL and 11,133 Mcf/d of natural gas. These assets are characterized by shallow wells with short cycle times and a manufacturing approach to development. In 2021, Baytex completed 116 (114.2 net) oil wells. As at December 31, 2021 we had proved plus probable reserves of 77 million boe (51 million proved; 26 million probable).

The undeveloped land base associated with the Viking assets consisted of 171,167 net acres at year-end 2021.

Peace River - Alberta

In the Peace River area of northwest Alberta we produce heavy gravity crude oil and natural gas from the Bluesky formation and heavy gravity crude oil from the Spirit River (a Clearwater equivalent) formation. The core of our developing Clearwater play is located on the Peavine Métis settlement. However, a portion of Clearwater prospective acreage overlays our legacy Peace River lands which are productive from the Bluesky formation. Production in the area occurs through primary and polymer flooding recovery methods. During 2021, production from the area averaged approximately 13,918 boe/d, comprised of 11,986 bbl/d of heavy oil, 31 bbl/d of NGL and 11,408 Mcf/d of natural gas. In 2021, Baytex drilled 12 (12.0 net) horizontal multi-lateral wells in this area. As at December 31, 2021, we had proved plus probable reserves of 48 million boe (28 million proved; 20 million probable).

Baytex held approximately 256,931 net undeveloped acres in this area at year-end 2021.

Lloydminster - Alberta and Saskatchewan

Our Lloydminster assets consist of several geographically dispersed heavy oil operations that include primary and thermal production. In some cases, Baytex's heavy oil reservoirs are water flooded and polymer flooded. In 2021, production averaged approximately 10,449 boe/d, which was comprised of 8,463 bbl/d of heavy oil, 1,739 bbl/d of bitumen, 6 bbl/d of light oil, and 1,448 Mcf/d of natural gas. In 2021, Baytex drilled 25 (21.5 net) oil wells in this area. As at December 31, 2021, we had proved plus probable reserves of 84 million boe (26 million proved; 58 million probable).

We held approximately 188,417 net undeveloped acres in this area at year-end 2021.

Duvernay - Alberta

Baytex holds a large 100% working interest land position in the emerging East Duvernay resource play in central Alberta. Production in the area occurs from the hydraulic fracturing of horizontal wells. In 2021, the Duvernay assets produced 2,008 boe/d, comprised of 1,645 bbl/d of light oil and NGL and 2,177 Mcf/d of natural gas. During 2021, Baytex drilled 2 (2.0 net) oil wells. As at December 31, 2021, our proved plus probable reserves are 22 million boe (12 million proved; 10 million probable) and our net undeveloped lands totaled approximately 223,007 net acres.

Average Production

The following table indicates our average daily production from our principal properties for the year ended December 31, 2021.

	Heavy Oil (bbl/d)	Bitumen (bbl/d)	Light and Medium Oil (bbl/d)	Tight Oil (bbl/d)	NGL[1] (bbl/d)	Shale Gas (Mcf/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada - Heavy								
Peace River	11,986	—	—	—	31	—	11,408	13,918
Lloydminster	8,463	1,739	6	—	—	—	1,448	10,449
Total	20,449	1,739	6	—	31	—	12,856	24,367
Canada - Light								
Viking	—	—	15,227	—	195	—	11,133	17,278
Duvernay	—	—	—	1,042	603	2,177	—	2,008
Remaining properties	—	—	477	—	1,033	—	25,566	5,771
Total	—	—	15,704	1,042	1,831	2,177	36,699	25,057
United States								
Eagle Ford	—	—	—	14,249	10,170	37,874	—	30,731
Grand Total	**20,449**	**1,739**	**15,710**	**15,291**	**12,032**	**40,051**	**49,555**	**80,156**

Note:

(1) Includes condensate.

Costs Incurred

The following table summarizes the property acquisition, exploration and development costs by country for the year ended December 31, 2021.

($000s)	Canada	United States	Total
Property acquisition costs			
Proved properties	60	—	60
Unproved properties	1,497	—	1,497
Property disposition	(7,211)	(593)	(7,804)
Total Property acquisition costs, net	(5,654)	(593)	(6,247)
Development Costs [1]	204,912	105,093	310,005
Exploration Costs [2]	3,298	—	3,298
Total	202,556	104,500	307,056

Notes:

(1) Development and facilities expenditures.

(2) Cost of land, geological and geophysical capital expenditures.

Oil and Gas Wells

The following table sets forth the number and status of wells in which we have a working interest as at December 31, 2021.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	746	629.5	1,331	886.3	334	248.6	711	564.4
BC	—	—	1	0.5	—	—	1	0.5
Saskatchewan	2,798	2,557.3	1,856	1,785.0	479	391.4	394	354.5
Texas	877	197.7	79	19.6	360	101.5	50	12.1
Total	4,421	3,384.5	3,267	2,691.4	1,173	741.5	1,156	931.5

Properties with No Attributed Reserves

The following table sets forth our undeveloped land holdings as at December 31, 2021.

	Undeveloped Acres	
	Gross	Net
Alberta	822,671	697,920
Saskatchewan	307,773	266,227
Total	1,130,444	964,147

Undeveloped land holdings are lands that have not been assigned reserves as at December 31, 2021. None of these undeveloped properties have high expected development or operating costs or contractual sales obligations to produce and sell at substantially lower prices than could be realized under normal market conditions.

We estimate the value of our net undeveloped land holdings at December 31, 2021 to be approximately $88.9 million, as compared to $129.7 million as at December 31, 2020. This internal evaluation generally represents the estimated replacement cost of our undeveloped land and excludes approximately 114,297 net acres of our undeveloped land that we expect to expire on or before December 31, 2022. In determining replacement cost, we analyzed land sale prices paid at provincial crown land sales for properties in the vicinity of our undeveloped land holdings over the preceding three years.

Tax Horizon

Baytex does not expect to pay any material cash income taxes prior to 2027 as forecasted using the average commodity price forecasts and inflation rates of McDaniel, GLJ Petroleum Consultants Ltd. and Sproule Associates Limited as of January 1, 2022 used to prepare the Reserves Report. This estimate and any amount of income tax we may be required to pay in the future is highly sensitive to assumptions regarding commodity prices, production, cash flow, capital expenditure levels and changes in governing tax laws. For additional information, see Note 14 of our audited consolidated financial statements for the year ended December 31, 2021 and the information under the heading "*Income Taxes*" in our MD&A for the year ended December 31, 2021.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which we participated during the year ended December 31, 2021.

	Exploratory Wells		Development Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Oil	—	—	222	170.0	222	170.0
Natural Gas	—	—	9	4.2	9	4.2
Stratigraphic	—	—	—	—	—	—
Service	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total	—	—	231	174.2	231	174.2

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ending December 31, 2022, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained under "*Statement of Reserves Data - Disclosure of Reserves Data*".

	Heavy Oil (bbl/d)	Bitumen (bbl/d)	Light and Medium Oil (bbl/d)	Tight Oil (bbl/d)	NGL (bbl/d)(1)	Shale Gas (Mcf/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
CANADA								
Total Proved	19,813	1,115	16,168	1,176	1,756	2,712	49,691	48,761
Total Proved plus Probable	21,530	1,268	17,543	1,294	1,945	2,959	53,645	53,014
UNITED STATES								
Total Proved	—	—	—	12,188	10,419	34,744	—	28,398
Total Proved plus Probable	—	—	—	12,571	10,700	35,611	—	29,207
TOTAL								
Total Proved	19,813	1,115	16,168	13,363	12,175	37,456	49,691	77,159
Total Proved plus Probable	21,530	1,268	17,543	13,865	12,646	38,570	53,645	82,220

Note:

(1) Includes condensate.

The two properties that account for 20% or more of the estimated 2022 production volumes are the Eagle Ford and the Viking. Estimated 2022 production volumes for the Eagle Ford is 28,398 boe/d on a total proved basis and 29,207 boe/d on a total proved plus probable basis. Estimated 2022 production volumes for the Viking is 17,874 boe/d on a total proved basis and 19,423 boe/d on a total proved plus probable basis.

Production History

The following table summarizes certain information in respect of the production, product prices received, royalties paid, production costs and resulting netback associated with our reserves data for the periods indicated below.

	Three Months Ended				Year Ended
	Dec. 31, 2021	Sep. 30, 2021	Jun. 30, 2021	Mar. 31, 2021	Dec. 31, 2021
Average Sales Volume [1]					
CANADA					
Light Oil (bbl/d)	14,727	15,559	14,697	17,894	15,710
Heavy Oil (bbl/d)	21,635	20,248	19,677	20,222	20,449
Bitumen (bbl/d)	1,847	1,748	1,592	1,767	1,739
Tight Oil (bbl/d)	1,472	767	787	1,141	1,042
NGL (bbl/d) [2]	1,902	1,436	1,956	2,163	1,862
Total liquids (bbl/d)	41,583	39,758	38,709	43,187	40,802
Shale Gas (Mcf/d)	2,767	1,908	2,033	1,998	2,177
Natural Gas (Mcf/d)	49,906	48,289	48,941	51,111	49,555
Total (boe/d)	50,362	48,124	47,205	52,039	49,424
UNITED STATES					
Tight Oil (bbl/d)	14,753	14,038	16,633	11,539	14,249
NGL (bbl/d) [2]	10,116	10,988	10,624	8,931	10,170
Total liquids (bbl/d)	24,869	25,026	27,257	20,470	24,419
Shale Gas (Mcf/d)	33,356	40,331	40,198	37,630	37,874
Total (boe/d)	30,428	31,748	33,957	26,741	30,731
TOTAL					
Light Oil (bbl/d)	14,727	15,559	14,697	17,894	15,710
Heavy Oil (bbl/d)	21,635	20,248	19,677	20,222	20,449
Bitumen (bbl/d)	1,847	1,748	1,592	1,767	1,739
Tight Oil (bbl/d)	16,225	14,805	17,420	12,680	15,291
NGL (bbl/d) [2]	12,018	12,424	12,580	11,094	12,032
Total liquids (bbl/d)	66,452	64,784	65,966	63,657	65,221
Shale Gas (Mcf/d)	36,123	42,239	42,231	39,628	40,051
Natural Gas (Mcf/d)	49,906	48,289	48,941	51,111	49,555
Total (boe/d)	80,789	79,872	81,162	78,780	80,156

	Three Months Ended				Year Ended
	Dec. 31, 2021	Sep. 30, 2021	Jun. 30, 2021	Mar. 31, 2021	Dec. 31, 2021
CANADA					
Average Net Production Prices [3]					
Light Oil ($/bbl)	91.07	82.07	74.50	64.30	77.44
Heavy Oil ($/bbl)	67.45	62.54	56.56	46.05	58.40
Bitumen ($/bbl)	71.37	64.55	58.97	50.93	61.69
Tight Oil ($/bbl)	91.88	83.48	76.19	66.87	80.61
NGL ($/bbl) [2]	46.87	43.40	27.85	28.20	35.87
Shale Gas ($/Mcf)	4.64	3.68	2.92	2.90	3.64
Natural Gas ($/Mcf)	4.65	3.71	3.06	3.03	3.62
Total ($/boe)	67.54	61.69	54.49	47.47	57.79
Royalties					
Light Oil and NGL ($/bbl) [2][4]	6.81	5.95	5.38	4.98	5.75
Heavy Oil ($/bbl)	10.63	10.99	9.14	7.08	9.50
Bitumen ($/bbl)	20.57	6.15	5.58	4.99	9.59
Tight Oil ($/bbl)	9.12	10.10	(0.77)	11.37	8.05
Shale Gas ($/Mcf)	0.30	0.28	0.15	0.23	0.24
Natural Gas ($/Mcf)	0.30	0.26	0.20	0.17	0.23
Total ($/boe)	8.15	7.38	6.10	5.27	6.72
Operating Expenses [5]					
Light Oil and NGL ($/bbl) [2][4]	12.66	11.88	12.02	11.73	12.06
Heavy Oil ($/bbl)	18.44	17.30	16.71	15.04	16.91
Bitumen ($/bbl)	20.23	18.31	26.24	20.19	21.11
Tight Oil ($/bbl)	9.66	8.29	7.07	8.42	8.52
Shale Gas ($/Mcf)	1.61	1.38	1.18	1.40	1.42
Natural Gas ($/Mcf)	2.17	1.96	2.05	1.85	2.01
Total ($/boe)	15.37	14.30	14.39	13.10	14.28
Transportation Expenses					
Light Oil and NGL ($/bbl) [2][4]	0.40	0.54	0.65	0.93	0.64
Heavy Oil ($/bbl)	3.05	2.96	2.88	2.94	2.96
Bitumen ($/bbl)	2.96	2.97	2.43	3.24	2.91
Tight Oil ($/bbl)	1.01	0.90	1.10	1.11	1.04
Shale Gas ($/Mcf)	0.17	0.15	0.18	0.19	0.17
Natural Gas ($/Mcf)	0.18	0.20	0.20	0.24	0.20
Total ($/boe)	1.76	1.77	1.74	1.88	1.79
Netback Received [3][6]					
Light Oil and NGL ($/bbl) [2][4]	66.14	60.44	50.97	42.77	54.59
Heavy Oil ($/bbl)	35.33	31.29	27.83	20.99	29.03
Bitumen ($/bbl)	27.61	37.12	24.72	22.51	28.08
Tight Oil ($/bbl)	72.09	64.19	68.79	45.97	63.00
Shale Gas ($/Mcf)	2.56	1.87	1.41	1.08	1.81
Natural Gas ($/Mcf)	2.00	1.29	0.61	0.77	1.18
Total ($/boe)	42.26	38.24	32.26	27.22	35.00

	Three Months Ended				Year Ended
	Dec. 31, 2021	Sep. 30, 2021	Jun. 30, 2021	Mar. 31, 2021	Dec. 31, 2021
UNITED STATES					
Average Net Production Prices [3]					
Tight Oil ($/bbl)	98.04	88.41	82.40	71.02	85.70
NGL ($/bbl) [2]	61.05	62.58	52.20	55.96	58.06
Shale Gas ($/Mcf)	6.70	5.00	3.59	7.84	5.70
Total ($/boe)	75.17	67.11	60.95	60.36	65.98
Royalties					
Tight Oil ($/bbl)	30.34	27.79	24.67	23.57	26.70
NGL ($/bbl) [2]	16.47	16.64	15.05	13.00	15.39
Shale Gas ($/Mcf)	1.92	1.38	0.94	2.17	1.58
Total ($/boe)	22.28	19.80	17.91	17.57	19.42
Operating Expenses [5][7]					
Tight Oil ($/bbl)	8.63	7.15	6.83	7.97	7.61
NGL ($/bbl) [2]	8.63	7.15	6.83	7.97	7.61
Shale Gas ($/Mcf)	1.44	1.19	1.14	1.33	1.27
Total ($/boe)	8.63	7.15	6.83	7.97	7.61
Netback Received [3][6]					
Tight Oil ($/bbl)	59.07	53.47	50.90	39.48	51.39
NGL ($/bbl) [2]	35.95	38.79	30.32	34.99	35.06
Shale Gas ($/Mcf)	3.34	2.43	1.51	4.34	2.85
Total ($/boe)	44.26	40.16	36.21	34.82	38.95

Notes:

(1) Before deduction of royalties.

(2) NGL includes condensate.

(3) Before the effects of commodity derivative instruments.

(4) In Canada, NGL volumes are grouped with light oil volumes for reporting purposes.

(5) Operating expenses are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions are required to allocate these costs between oil, natural gas and NGL production.

(6) Netback is calculated by subtracting royalties, operating and transportation expenses from revenues.

(7) In the U.S., transportation expense is included in operating expenses for reporting purposes.

Marketing Arrangements and Forward Contracts

In Canada, we market our oil and natural gas production with attention to maximizing value and counterparty performance. We have a portfolio of sales contracts with a variety of pricing mechanisms, term commitments and customers. For our heavy oil volumes, this includes rail commitments. In the United States, production from our assets is marketed by the operator.

The Corporation also has a risk management policy pursuant to which we utilize various derivative financial instruments and physical sales contracts to manage our exposure to fluctuations in commodity prices, foreign exchange and interest rates. We also use derivative instruments in various operational markets to optimize our supply or production chain.

When marketing and hedging we engage a number of reputable counterparties to ensure competitiveness, while also managing counterparty credit exposure. For details on our contractual commitments to sell natural gas and crude oil which were outstanding at February 24, 2022, see Note 17 to our audited consolidated financial statements for the year ended December 31, 2021. See *Risk Factors.*

STATEMENT OF RESERVES DATA

The Baytex Reserves Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101. The statement of reserves data and other oil and natural gas information set forth below is dated December 31, 2021. The effective date of the Baytex Reserves Report is December 31, 2021 and the preparation date of the statement is February 3, 2022. The Baytex Reserves Report was prepared using the average commodity price forecasts and inflation rates of McDaniel, GLJ Petroleum Consultants Ltd. and Sproule Associates Limited as of January 1, 2022.

Disclosure of Reserves Data

The tables below are a combined summary as at December 31, 2021 of our proved and probable heavy oil, bitumen, light and medium oil, tight oil, NGL, conventional natural gas and shale gas reserves and the net present value of the future net revenue attributable to such reserves evaluated in the Baytex Reserves Report. Our reserves are located in Canada (Alberta and Saskatchewan) and the United States (Texas).

All evaluations of future net revenue are after the deduction of future income tax expenses (unless otherwise noted in the tables), royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of our reserves. There is no assurance that the forecast price and cost assumptions contained in the Baytex Reserves Report will be attained and variations could be material. The tables summarize the data contained in the Baytex Reserves Report and, as a result, may contain slightly different numbers and columns in the tables may not add due to rounding. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to or following the tables below.

The recovery and reserves estimates described herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Readers should review the definitions and information contained in "*Selected Terms - Reserves Definitions*", "- *Reserves and Reserve Categories*" and "- *Development and Production Status*" in conjunction with the following tables and notes. For more information as to the risks involved, see "*Risk Factors*".

SUMMARY OF OIL AND NATURAL GAS RESERVES
AS OF DECEMBER 31, 2021
FORECAST PRICES AND COSTS

CANADA

	TIGHT OIL		LIGHT AND MEDIUM OIL		HEAVY OIL	
RESERVES CATEGORY	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**
PROVED:						
Developed Producing	1,476	1,322	18,564	17,436	23,735	20,775
Developed Non-Producing	—	—	664	617	765	689
Undeveloped	4,356	3,833	26,781	24,891	21,503	19,139
TOTAL PROVED	5,832	5,155	46,009	42,944	46,003	40,602
PROBABLE	5,189	4,439	23,296	21,399	29,705	25,547
TOTAL PROVED PLUS PROBABLE	11,021	9,593	69,305	64,343	75,709	66,149

CANADA

	BITUMEN		SHALE GAS		CONVENTIONAL NATURAL GAS [1]	
RESERVES CATEGORY	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MMcf)**	**Net (MMcf)**
PROVED:						
Developed Producing	641	575	4,451	4,124	65,234	58,749
Developed Non-Producing	—	—	—	—	1,973	1,687
Undeveloped	4,197	3,857	9,696	8,871	37,216	34,310
TOTAL PROVED	4,838	4,432	14,147	12,995	104,423	94,745
PROBABLE	45,874	37,186	11,778	10,659	62,394	56,747
TOTAL PROVED PLUS PROBABLE	50,713	41,618	25,925	23,654	166,817	151,492

CANADA

	NATURAL GAS LIQUIDS [2]		TOTAL RESERVES	
RESERVES CATEGORY	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mboe)**	**Net (Mboe)**
PROVED:				
Developed Producing	2,460	2,034	58,491	52,620
Developed Non-Producing	48	37	1,806	1,623
Undeveloped	3,593	3,197	68,249	62,114
TOTAL PROVED	6,101	5,267	128,546	116,357
PROBABLE	4,803	4,067	121,229	103,872
TOTAL PROVED PLUS PROBABLE	10,904	9,335	249,775	220,229

UNITED STATES

RESERVES CATEGORY	TIGHT OIL Gross (Mbbl)	TIGHT OIL Net (Mbbl)	SHALE GAS Gross (MMcf)	SHALE GAS Net (MMcf)	NATURAL GAS LIQUIDS [2] Gross (Mbbl)	NATURAL GAS LIQUIDS [2] Net (Mbbl)
PROVED:						
Developed Producing	25,148	18,476	95,327	70,337	29,393	21,701
Developed Non-Producing	314	232	2,448	1,812	804	593
Undeveloped	21,922	16,049	119,516	87,731	35,838	26,324
TOTAL PROVED	47,384	34,757	217,292	159,879	66,035	48,618
PROBABLE	16,296	11,965	73,151	53,847	22,948	16,903
TOTAL PROVED PLUS PROBABLE	63,680	46,722	290,443	213,726	88,983	65,521

UNITED STATES

RESERVES CATEGORY	TOTAL RESERVES Gross (Mboe)	TOTAL RESERVES Net (Mboe)
PROVED:		
Developed Producing	70,428	51,899
Developed Non-Producing	1,527	1,127
Undeveloped	77,680	56,995
TOTAL PROVED	149,635	110,021
PROBABLE	51,436	37,842
TOTAL PROVED PLUS PROBABLE	201,070	147,864

TOTAL

RESERVES CATEGORY	TIGHT OIL Gross (Mbbl)	TIGHT OIL Net (Mbbl)	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)	HEAVY OIL Gross (Mbbl)	HEAVY OIL Net (Mbbl)
PROVED:						
Developed Producing	26,623	19,797	18,564	17,436	23,735	20,775
Developed Non-Producing	314	232	664	617	765	689
Undeveloped	26,278	19,882	26,781	24,891	21,503	19,139
TOTAL PROVED	53,216	39,911	46,009	42,944	46,003	40,602
PROBABLE	21,485	16,404	23,296	21,399	29,705	25,547
TOTAL PROVED PLUS PROBABLE	74,701	56,315	69,305	64,343	75,709	66,149

TOTAL

RESERVES CATEGORY	BITUMEN Gross (Mbbl)	BITUMEN Net (Mbbl)	SHALE GAS Gross (MMcf)	SHALE GAS Net (MMcf)	CONVENTIONAL NATURAL GAS [1] Gross (MMcf)	CONVENTIONAL NATURAL GAS [1] Net (MMcf)
PROVED:						
Developed Producing	641	575	99,778	74,461	65,234	58,749
Developed Non-Producing	—	—	2,448	1,812	1,973	1,687
Undeveloped	4,197	3,857	129,213	96,601	37,216	34,310
TOTAL PROVED	4,838	4,432	231,439	172,874	104,423	94,745
PROBABLE	45,874	37,186	84,928	64,506	62,394	56,747
TOTAL PROVED PLUS PROBABLE	50,713	41,618	316,367	237,381	166,817	151,492

TOTAL

RESERVES CATEGORY	NATURAL GAS LIQUIDS [2] Gross (Mbbl)	NATURAL GAS LIQUIDS [2] Net (Mbbl)	TOTAL RESERVES Gross (Mboe)	TOTAL RESERVES Net (Mboe)
PROVED:				
Developed Producing	31,853	23,735	128,919	104,519
Developed Non-Producing	852	630	3,333	2,751
Undeveloped	39,431	29,521	145,929	119,108
TOTAL PROVED	72,137	53,885	278,181	226,378
PROBABLE	27,751	20,970	172,665	141,715
TOTAL PROVED PLUS PROBABLE	99,888	74,856	450,846	368,093

Notes:

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

(2) Natural gas liquids includes condensate.

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2021
FORECAST PRICES AND COSTS

CANADA	**BEFORE INCOME TAXES DISCOUNTED AT (%/year)**					**UNIT VALUE BEFORE TAX**
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**	**10% $/boe**
PROVED:						
Developed Producing	338,313	758,973	836,791	829,112	798,491	15.90
Developed Non-Producing	45,808	40,859	36,942	33,760	31,119	22.76
Undeveloped	1,184,376	852,606	621,959	459,039	341,391	10.01
TOTAL PROVED	1,568,497	1,652,438	1,495,692	1,321,911	1,171,001	12.85
PROBABLE	3,126,148	1,834,880	1,212,619	868,779	659,179	11.67
TOTAL PROVED PLUS PROBABLE	4,694,645	3,487,318	2,708,311	2,190,691	1,830,180	12.30

UNITED STATES	**BEFORE INCOME TAXES DISCOUNTED AT (%/year)**					**UNIT VALUE BEFORE TAX**
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**	**10% $/boe**
PROVED:						
Developed Producing	2,060,655	1,475,569	1,151,534	958,381	830,998	22.19
Developed Non-Producing	48,640	31,555	23,290	18,510	15,410	20.66
Undeveloped	1,667,604	1,095,366	777,089	581,096	450,695	13.63
TOTAL PROVED	3,776,899	2,602,490	1,951,913	1,557,987	1,297,103	17.74
PROBABLE	1,469,938	718,749	423,528	280,136	199,800	11.19
TOTAL PROVED PLUS PROBABLE	5,246,837	3,321,239	2,375,441	1,838,122	1,496,902	16.07

TOTAL	**BEFORE INCOME TAXES DISCOUNTED AT (%/year)**					**UNIT VALUE BEFORE TAX**
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**	**10% $/boe**
PROVED:						
Developed Producing	2,398,968	2,234,542	1,988,325	1,787,492	1,629,489	19.02
Developed Non-Producing	94,448	72,414	60,233	52,271	46,529	21.90
Undeveloped	2,851,980	1,947,972	1,399,048	1,040,135	792,086	11.75
TOTAL PROVED	5,345,396	4,254,928	3,447,605	2,879,898	2,468,103	15.23
PROBABLE	4,596,087	2,553,629	1,636,147	1,148,915	858,979	11.55
TOTAL PROVED PLUS PROBABLE	9,941,482	6,808,557	5,083,752	4,028,813	3,327,082	13.81

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2021
FORECAST PRICES AND COSTS

CANADA	**AFTER INCOME TAXES DISCOUNTED AT (%/year)[1]**				
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	338,313	758,973	836,791	829,112	798,491
Developed Non-Producing	45,808	40,859	36,942	33,760	31,119
Undeveloped	1,101,220	789,713	573,605	421,319	311,582
TOTAL PROVED	1,485,341	1,589,546	1,447,338	1,284,191	1,141,192
PROBABLE	2,539,392	1,435,539	925,132	653,322	492,703
TOTAL PROVED PLUS PROBABLE	4,024,732	3,025,084	2,372,470	1,937,513	1,633,895

UNITED STATES	**AFTER INCOME TAXES DISCOUNTED AT (%/year)[1]**				
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	1,870,944	1,386,059	1,102,621	928,355	810,610
Developed Non-Producing	38,208	25,657	19,656	16,151	13,822
Undeveloped	1,303,502	864,244	618,267	466,328	364,849
TOTAL PROVED	3,212,654	2,275,961	1,740,545	1,410,834	1,189,281
PROBABLE	1,152,711	561,883	330,346	218,508	156,235
TOTAL PROVED PLUS PROBABLE	4,365,365	2,837,844	2,070,891	1,629,341	1,345,516

TOTAL	**AFTER INCOME TAXES DISCOUNTED AT (%/year)[1]**				
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	2,209,257	2,145,032	1,939,412	1,757,467	1,609,101
Developed Non-Producing	84,016	66,516	56,599	49,911	44,941
Undeveloped	2,404,722	1,653,958	1,191,872	887,647	676,432
TOTAL PROVED	4,697,995	3,865,506	3,187,883	2,695,025	2,330,474
PROBABLE	3,692,103	1,997,421	1,255,478	871,829	648,937
TOTAL PROVED PLUS PROBABLE	8,390,098	5,862,928	4,443,361	3,566,854	2,979,411

Note:

(1) The after-tax net present value of future net revenue from our oil and gas properties reflects the tax burden on the properties on a theoretical stand-alone basis. It does not consider our corporate structure or any tax planning and therefore does not provide an estimate of the cumulative after-tax value of our consolidated business entities, which may be significantly different.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS OF DECEMBER 31, 2021
FORECAST PRICES AND COSTS

($000s)	REVENUE	ROYALTIES	OPERAT-ING COSTS	DEVELOP-MENT COSTS	WELL ABANDON-MENT COSTS[1]	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
TOTAL PROVED RESERVES								
Canada	7,737,265	798,628	2,684,566	1,605,910	1,079,664	1,568,497	83,156	1,485,341
United States	9,883,762	3,075,963	2,096,795	804,509	129,596	3,776,899	564,244	3,212,654
Total	17,621,027	3,874,591	4,781,361	2,410,419	1,209,260	5,345,396	647,401	4,697,995
TOTAL PROVED PLUS PROBABLE RESERVES								
Canada	15,821,233	2,044,163	5,309,482	2,634,165	1,138,778	4,694,645	669,913	4,024,732
United States	13,909,378	4,330,198	3,069,633	1,116,165	146,545	5,246,837	881,472	4,365,366
Total	29,730,611	6,374,361	8,379,115	3,750,330	1,285,323	9,941,482	1,551,385	8,390,098

Note:

(1) Includes well abandonment, decommissioning and reclamation costs for all producing and non-producing wells and facilities and to be incurred as a result of future development activity.

FUTURE NET REVENUE BY PRODUCT TYPE
AS OF DECEMBER 31, 2021
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCT TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE [1] ($/bbl; $/Mcf)
Proved	Light and Medium Crude Oil (including solution gas and associated byproducts)	844,540	19.67
	Heavy Crude Oil (including solution gas and associated byproducts)	457,262	11.26
	Bitumen (including solution gas and associated byproducts)	58,017	13.09
	Tight Oil (including solution gas and associated byproducts)	1,290,271	32.33
	Natural Gas (associated and non-associated) (including associated byproducts)	30,441	0.63
	Shale Gas (including associated byproducts)	767,074	6.80
	Total	3,447,605	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and associated byproducts)	1,379,371	21.44
	Heavy Crude Oil (including solution gas and associated byproducts)	823,224	12.45
	Bitumen (including solution gas and associated byproducts)	252,186	6.06
	Tight Oil (including solution gas and associated byproducts)	1,623,609	28.83
	Natural Gas (associated and non-associated) (including associated byproducts)	63,257	0.83
	Shale Gas (including associated byproducts)	942,105	6.28
	Total	5,083,752	

Note:

(1) Unit values are based on major product type net reserves volumes.

Pricing Assumptions

The forecast cost and price assumptions include increases in actual wellhead selling prices and take into account inflation with respect to future operating and capital costs. The reference pricing used in the Baytex Reserves Report is as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2021 (1)

	Oil			Natural Gas			
Year	WTI Crude Oil (2) ($US/bbl)	Edmonton Light Crude Oil (3) ($Cdn/bbl)	Western Canadian Select (4) ($Cdn/bbl)	Henry Hub (5) ($US/MMbtu)	AECO Spot (6) ($Cdn/MMbtu)	Inflation Rate (7) (%/Yr)	Exchange Rate (8) ($US/$Cdn)
Historical							
2017	50.90	62.85	50.70	3.00	2.40	1.6	0.770
2018	64.95	69.65	49.95	3.05	1.55	2.3	0.770
2019	57.00	69.00	58.70	2.55	1.60	2.0	0.755
2020	39.25	45.00	35.40	2.05	2.25	(0.1)	0.745
2021	67.95	80.25	68.80	3.90	3.55	1.4	0.800
Forecast (9)							
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

Notes:

(1) Each price from the forecast was adjusted for quality differentials and transportation costs applicable to the specified product and evaluation area.
(2) Price used in the preparation of tight oil, condensate, and natural gas liquids reserves in the United States.
(3) Price used in the preparation of light and medium crude oil and natural gas liquids reserves in Canada.
(4) Price used in the preparation of heavy oil and bitumen reserves in Canada.
(5) Price used in the preparation of shale gas reserves in the United States.
(6) Price used in the preparation of natural gas reserves in Canada.
(7) Inflation rates for forecasting prices and costs.
(8) Exchange rate used to generate the benchmark reference prices in this table.
(9) After 2031 prices and costs escalate at 2.0% annually and the exchange rate remains 0.797.

Weighted average prices realized by us for the year ended December 31, 2021, excluding hedging activities, were $58.40/bbl for heavy oil, $61.69/bbl for bitumen, $77.44/bbl for light oil, $80.61/bbl for tight oil, $35.87/bbl for NGL, $3.64/Mcf for shale gas and $3.62/Mcf for natural gas.

RECONCILIATION OF
GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

CANADA	HEAVY OIL			BITUMEN		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2020	35,412	30,544	65,956	5,737	46,093	51,830
Extensions	8,977	(760)	8,217	—	—	—
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions	2,949	(1,721)	1,228	(394)	(216)	(610)
Discoveries	—	—	—	—	—	—
Acquisitions	1,228	458	1,686	—	—	—
Dispositions	(260)	(225)	(485)	—	—	—
Economic Factors	5,160	1,409	6,570	130	(2)	127
Production	(7,464)	—	(7,464)	(635)	—	(635)
December 31, 2021	46,003	29,705	75,709	4,838	45,874	50,713

CANADA	LIGHT AND MEDIUM OIL			TIGHT OIL		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2020	52,067	25,688	77,755	4,380	4,748	9,128
Extensions	3,227	2,413	5,640	1,508	334	1,842
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions [1]	(6,059)	(5,357)	(11,416)	233	46	279
Discoveries	—	—	—	—	—	—
Acquisitions	3	—	3	—	—	—
Dispositions	(2)	(5)	(7)	—	—	—
Economic Factors	2,509	556	3,065	91	61	153
Production	(5,734)	—	(5,734)	(380)	—	(380)
December 31, 2021	46,009	23,296	69,305	5,832	5,189	11,021

DA	NATURAL GAS LIQUIDS [2]			SHALE GAS		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
ber 31, 2020	4,468	4,840	9,309	9,244	9,497	18,741
nsions	970	(124)	846	3,885	829	4,714
Drilling	—	—	—	—	—	—
oved Recovery	—	—	—	—	—	—
nical Revisions	794	594	1,388	1,572	1,324	2,896
overies	—	—	—	—	—	—
isitions	—	—	—	—	—	—
ositions	(13)	(256)	(269)	—	—	—
omic Factors	562	(251)	311	242	127	369
uction	(680)	—	(680)	(795)	—	(795)
ber 31, 2021	6,101	4,803	10,904	14,147	11,778	25,925

DA	CONVENTIONAL NATURAL GAS [3]			OIL EQUIVALENT		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
ber 31, 2020	87,894	86,778	174,671	118,254	127,959	246,212
nsions	16,032	(9,810)	6,222	18,002	366	18,368
Drilling	—	—	—	—	—	—
oved Recovery	—	—	—	—	—	—
nical Revisions	(1,649)	(70)	(1,719)	(2,491)	(6,445)	(8,936)
overies	—	—	—	—	—	—
isitions	—	—	—	1,231	458	1,689
ositions	(313)	(7,224)	(7,536)	(327)	(1,690)	(2,017)
omic Factors	20,547	(7,280)	13,267	11,917	582	12,499
uction	(18,088)	—	(18,088)	(18,040)	—	(18,040)
ber 31, 2021	104,423	62,394	166,817	128,546	121,229	249,775

UNITED STATES	TIGHT OIL			NATURAL GAS LIQUIDS [2]		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2020	48,936	19,894	68,830	68,007	27,920	95,927
Extensions	2,862	(2,650)	212	3,323	(2,865)	458
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions	287	(1,064)	(776)	(2,173)	(2,228)	(4,401)
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	(20)	(5)	(26)	(7)	(2)	(9)
Economic Factors	520	121	641	597	123	720
Production	(5,201)	—	(5,201)	(3,712)	—	(3,712)
December 31, 2021	47,384	16,296	63,680	66,036	22,948	88,983

D *STATES*	SHALE GAS			OIL EQUIVALENT		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
ber 31, 2020	217,090	87,355	304,445	153,125	62,373	215,497
nsions	12,281	(10,884)	1,397	8,232	(7,329)	903
Drilling	—	—	—	—	—	—
oved Recovery	—	—	—	—	—	—
nical Revisions [1]	27	(3,727)	(3,700)	(1,881)	(3,913)	(5,794)
overies	—	—	—	—	—	—
isitions	—	—	—	—	—	—
ositions	(35)	(9)	(45)	(33)	(9)	(42)
omic Factors	1,753	416	2,169	1,409	314	1,723
uction	(13,824)	—	(13,824)	(11,217)	—	(11,217)
ber 31, 2021	217,292	73,151	290,443	149,635	51,436	201,070

TOTAL	HEAVY OIL			BITUMEN		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2020	35,412	30,544	65,956	5,737	46,093	51,830
Extensions	8,977	(760)	8,217	—	—	—
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions	2,949	(1,721)	1,228	(394)	(216)	(610)
Discoveries	—	—	—	—	—	—
Acquisitions	1,228	458	1,686	—	—	—
Dispositions	(260)	(225)	(485)	—	—	—
Economic Factors	5,160	1,409	6,570	130	(2)	127
Production	(7,464)	—	(7,464)	(635)	—	(635)
December 31, 2021	46,003	29,705	75,709	4,838	45,874	50,713

TOTAL	LIGHT AND MEDIUM OIL			TIGHT OIL		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2020	52,067	25,688	77,755	53,316	24,642	77,958
Extensions	3,227	2,413	5,640	4,370	(2,315)	2,054
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions	(6,059)	(5,357)	(11,416)	520	(1,018)	(498)
Discoveries	—	—	—	—	—	—
Acquisitions	3	—	3	—	—	—
Dispositions	(2)	(5)	(7)	(20)	(5)	(26)
Economic Factors	2,509	556	3,065	612	182	794
Production	(5,734)	—	(5,734)	(5,581)	—	(5,581)
December 31, 2021	46,009	23,296	69,305	53,216	21,485	74,701

TOTAL	NATURAL GAS LIQUIDS [2]			SHALE GAS		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2020	72,475	32,760	105,235	226,334	96,852	323,186
Extensions	4,294	(2,989)	1,304	16,165	(10,055)	6,110
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions	(1,379)	(1,634)	(3,013)	1,599	(2,403)	(804)
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	(19)	(258)	(278)	(35)	(9)	(45)
Economic Factors	1,159	(127)	1,031	1,995	543	2,538
Production	(4,392)	—	(4,392)	(14,619)	—	(14,619)
December 31, 2021	72,137	27,751	99,888	231,439	84,928	316,367

TOTAL	CONVENTIONAL NATURAL GAS [3]			OIL EQUIVALENT		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2020	87,894	86,778	174,671	271,378	190,332	461,710
Extensions	16,032	(9,810)	6,222	26,234	(6,963)	19,271
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions [1]	(1,649)	(70)	(1,719)	(4,372)	(10,359)	(14,730)
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	1,231	458	1,689
Dispositions	(313)	(7,224)	(7,536)	(360)	(1,699)	(2,058)
Economic Factors	20,547	(7,280)	13,267	13,326	895	14,221
Production	(18,088)	—	(18,088)	(29,257)	—	(29,257)
December 31, 2021	104,423	62,394	166,817	278,181	172,665	450,846

Notes:

(1) 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.

(2) Natural gas liquids includes condensate.

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

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

We allocate development capital to our assets annually. We reduce risk by technically assessing the prior year's results from our development programs before committing additional capital. Furthermore, planned activity levels vary each year due to factors such as prevailing commodity prices, capital availability, operational spacing considerations, timing of infrastructure construction and regulatory processes. This approach means that in most cases it will take longer than three years to develop our proved undeveloped reserves and longer than five years to develop our proved plus probable undeveloped reserves. With the exception of our Gemini SAGD project, we plan to develop the majority of our proved undeveloped reserves over the next five years and our probable undeveloped reserves over the next seven years.

At our Gemini SAGD project, steam generation represents a large proportion of the capital and operating costs. Therefore, our development plans anticipate that, in order to make the most efficient use of our steam generating and oil treating facilities, the drilling and steaming of wells (once commenced) would take place over approximately 26 years. We have booked 44.5 MMbbls of probable undeveloped reserves to the Gemini SAGD project.

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were attributed during, and the volume booked at year-end for, the three most recently completed financial years.

	Light and Medium Oil Gross (Mbbl)		Tight Oil Gross (Mbbl)		Heavy Oil Gross (Mbbl)		Bitumen Gross (Mbbl)	
Year	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2019	6,136	33,322	5,373	32,250	2,322	22,691	—	1,892
2020	2,039	31,601	1,152	29,805	82	13,499	3,027	4,434
2021	2,062	26,781	3,767	26,278	8,208	21,503	—	4,197

	Conventional Natural Gas Gross (MMcf)		Shale Gas Gross (MMcf)		Natural Gas Liquids Gross (Mbbl)	
Year	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2019	3,116	45,272	20,951	133,516	6,758	43,333
2020	12,306	29,438	2,676	128,541	1,140	40,167
2021	12,540	37,216	14,415	129,213	4,186	39,431

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were attributed during, and the volume booked at year-end for, the three most recently completed financial years.

	Light and Medium Oil Gross (Mbbl)		Tight Oil Gross (Mbbl)		Heavy Oil Gross (Mbbl)		Bitumen Gross (Mbbl)	
Year	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2019	8,613	22,643	2,879	18,895	767	28,409	—	44,954
2020	(2,038)	19,315	1,174	19,619	226	22,844	696	45,588
2021	2,464	16,940	(2,379)	15,839	(330)	21,391	—	45,567

	Conventional Natural Gas Gross (MMcf)		Shale Gas Gross (MMcf)		Natural Gas Liquids Gross (Mbbl)	
Year	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2019	1,260	80,635	2,421	76,884	47	27,737
2020	(11,386)	70,042	5,499	76,050	1,006	25,715
2021	(7,079)	38,947	(10,331)	64,259	(2,904)	20,836

Significant Factors or Uncertainties

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change.

The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, commodity prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices and reservoir performance. Such revisions can be either positive or negative.

In the event that prices for oil and gas are not consistent with those used to prepare the Baytex Reserves Report, the volume of our reserves, their net present value and our expected revenues will differ, perhaps materially so, from those stated in the Baytex Reserves Report.

In connection with our operations, we will be liable for our share of ongoing environmental obligations and for the ultimate reclamation of our surface leases, wells and facilities. The total liability associated with these existing surface leases, wells and facilities, inflated at 2% per year, is estimated to be $1,096 million undiscounted ($213 million discounted at 10 percent). This is comprised of $426 million undiscounted ($58 million discounted at 10 percent) associated with active properties, $426 million undiscounted ($121 million discounted at 10 percent) associated with inactive properties, and $244 million undiscounted ($34 million discounted at 10 percent) associated with facilities.

Future Development Costs

The following table sets forth development costs deducted in the estimation of the future net revenue attributable to the reserve categories noted below (using forecast prices and costs).

FUTURE DEVELOPMENT COSTS
AS OF DECEMBER 31, 2021
FORECAST PRICES AND COSTS
($000s)

	CANADA		UNITED STATES		TOTAL	
	Proved Reserves	Proved plus Probable Reserves	Proved Reserves	Proved plus Probable Reserves	Proved Reserves	Proved plus Probable Reserves
2022	303,653	310,448	112,453	112,453	416,106	422,901
2023	331,262	365,526	174,268	174,268	505,530	539,794
2024	339,213	384,231	177,885	177,885	517,098	562,116
2025	298,942	391,084	190,259	190,259	489,201	581,344
2026	248,592	463,379	149,645	193,730	398,237	657,108
Remaining	84,247	719,497	—	267,571	84,247	987,067
Total (undiscounted)	1,605,910	2,634,165	804,509	1,116,165	2,410,419	3,750,330

We expect to fund the development costs of our reserves through a combination of internally generated cash flow, debt and equity financing. Planned activity levels vary each year due to factors such as capital availability, prevailing commodity prices and regulatory processes.

There can be no guarantee that funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the Baytex Reserves Report. Failure to develop those reserves could have a negative impact on our future cash flow.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth herein and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized and the costs thereof. We do not anticipate that interest or other funding costs would make development of any of these properties uneconomic.

RISK FACTORS

You should carefully consider the following risk factors, as well as the other information contained in this AIF and our other public filings before making an investment decision. If any of the risks described below materialize, our business, reputation, financial condition, results of operations and cash flow could be materially and adversely affected, which may materially affect the market price of our securities. Additional risks and uncertainties not currently known to us that we currently view as immaterial may also materially and adversely affect us. Residents of the United States and other non-residents of Canada should have additional regard to the risk factors under the heading "*Certain Risks for United States and other non-resident Shareholders*".

The information set forth below contains forward-looking statements, which are qualified by the information contained in the section of this AIF entitled "*Special Notes to Reader - Forward-Looking Statements*".

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 Canadian GAAP. If crude oil and natural gas forecast prices change, the carrying value of our assets could be subject to revision and our net earnings could be adversely affected.

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

Regulatory and Policy Initiatives

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

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

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

Although we provide for the necessary amounts in our annual capital budget to fund our currently estimated obligations, there can be no assurance that we will be able to satisfy our actual future obligations associated with GHG emissions from such funds. For more information on the evolution and status of climate change and related environmental legislation, see "*Industry Conditions - Climate Change Regulation*".

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. The Corporation cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business and financial condition by decreasing its cash flow from operating activities and the value of its 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. For further details, see *"Legal Proceedings and Regulatory Actions"*.

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 governmental authorities under existing controls, legislation or regulations, the implementation of new controls, legislation or regulations or the modification of existing controls, legislation or regulations affecting the oil and gas industry could reduce demand for crude oil and natural gas, increase our costs, or delay or restrict our operations, all of which would have a material adverse effect on our financial condition, results of operations or prospects. See "*Industry Conditions*".

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. See " *Industry Conditions*".

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 the Corporation's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

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

The Corporation undertakes or intends to undertake certain hydraulic fracturing, SAGD, CCS and waterflooding programs. To undertake such operations the Corporation needs to have access to sufficient volumes of water, or other liquids. There is no certainty that the Corporation 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 the Corporation is 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 the Corporation is ultimately able to produce from its reserves.

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

The safe disposal of hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal, 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 Corporation's 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. For more information about our commodity hedging program, see *"General Description of our Business - Marketing Arrangements and Forward Contracts"*.

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 this 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 as set forth under "*Statement of Reserves Data - Pricing Assumptions*". 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. The Corporation competes 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 the Corporation. As a result, some of the Corporation's competitors may have greater opportunities and be able to access, services or vendors that the Corporation is not able to access, thereby limiting its 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. For further details, see *"Legal Proceedings and Regulatory Actions"*.

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. See "*Description of Capital Structure*".

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.

Additional information on the risks, assumption and uncertainties are found under the heading " *Notice to Reader – Special Note Regarding Forward-Looking Statements*" of this AIF.

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.

We have included in this AIF estimates of proved reserves and proved plus probable reserves. 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, proved, probable and proved plus probable reserves disclosed in this AIF may not be comparable to United States standards.

As a consequence of the foregoing, our reserves estimates and production volumes in this AIF 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.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive controls and regulation in respect of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government. The oil and gas industry is also subject to agreements among the governments of Canada, Alberta, Saskatchewan, the United States and Texas with respect to pricing and taxation of oil and natural gas. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada and the United States.

Pricing and Marketing

Oil

In Canada and the United States, producers of oil are entitled to negotiate sales contracts directly with oil purchasers. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional markets and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale.

Oil can be exported from Canada provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**") and the term of the export contract does not exceed one year in the case of light crude oil and two years in the case of heavy crude oil. Any Canadian oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the NEB. Oil exports from the United States are controlled by the United States Department of Commerce. However, since December, 2015, only exports to embargoed or sanctioned countries require authorization from the U.S. Department of Commerce.

In an effort to increase the price for crude oil and bitumen produced in Alberta, the Government of Alberta announced production curtailments which came into effect on January 1, 2019. As implemented, each producer was provided a production allocation determined in part based upon each producer's prior year production measured over a one month or six month period. Production curtailments were removed as of December 2020 and the Government of Alberta has stated that it will monitor market conditions and may reintroduce the curtailments if storage levels approach capacity.

Natural Gas

In Canada and the United States, producers of natural gas are entitled to negotiate sales contracts directly with purchasers. Supply and demand determine the price of natural gas, which is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system, at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short-term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms.

Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an export license from the NEB.

Natural gas exported from the United States is regulated principally by the Federal Energy Regulatory Commission (" **FERC**") and the United States Department of Energy ("**DOE**"). U.S. law provides for very limited regulation of exports to and imports from any country that has entered into a free trade agreement with the United States that provides for national treatment of trade in natural gas; however, the DOE regulation of imports and exports from and to countries without such free trade agreements is more comprehensive.

The FERC regulates rates and service conditions for the transportation of natural gas in interstate commerce. The prices and terms of access to intrastate pipeline transportation are subject to state regulation. In Texas, the primary regulator is the Railroad Commission of Texas ("**RRC**"). Facilities used in the production or gathering of natural gas in interstate commerce are generally exempt from FERC jurisdiction. However, the distinction between FERC-regulated transmission pipelines and unregulated gathering systems is made by the FERC on a case-by-case basis and has been subject to extensive litigation.

North American Free Trade

The North American Free Trade Agreement among the governments of Canada, the United States and Mexico came into force on January 1, 1994. On July 1, 2020 this agreement was updated and replaced by the United States Mexico Canada Agreement "**USMCA**". In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36-month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement, except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. USMCA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

In addition to federal regulation, each province in Canada and each state in the United States has legislation and regulations that govern royalties, production rates and other matters. The royalty regime is a significant factor in the profitability of hydrocarbon production. Royalties payable on production from lands other than Crown lands in Canada and federal and state lands in the United States are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain taxes and royalties. Royalties from production on Crown lands in Canada and federal and state lands in the United States are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced.

From time to time the federal and provincial governments in Canada and the federal and state governments in the United States create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced to encourage specific types of exploration and development activity.

Land Tenure

In the Provinces of Alberta and Saskatchewan, the rights to crude oil and natural gas are predominantly owned by the provincial government. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses, and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. In the United States, private ownership of the rights to crude oil and natural gas is predominant. Where mineral rights are privately owned, the rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated. Private ownership of oil and natural gas also exists in western Canada. Government and private leases are generally granted for an initial fixed term but may generally be continued provided certain minimum levels of drilling operations or production have been achieved and all lease rentals have been timely paid, subject to certain exceptions.

To develop minerals, including oil and gas, it is necessary for the mineral estate owner(s) to have access to the surface estate. Under common law in Canada and the United States, the mineral estate is considered the "dominant" estate with the right to extract minerals subject to reasonable use of the surface. Each province and state has developed and adopted their own statutes that operators must follow both prior to drilling and following drilling, including notification requirements and the provision of compensation for lost land use and surface damages. The surface rights required for pipelines and facilities are generally governed by leases, easements, rights-of-way, permits or licenses granted by landowners or governmental authorities.

Liability Management Rating Programs

The provinces of Alberta and Saskatchewan both have liability management programs in respect of conventional upstream oil and gas wells, facilities and pipelines. Both programs require a licensee whose deemed liabilities equal or exceed its deemed assets within the jurisdiction to provide a security deposit. In response to a number of insolvencies, Alberta and Saskatchewan have made their liability management programs more stringent in recent years. In particular, a licensee is held to a higher standard when accepting the transfer of licensees from a third party. This has reduced the number of parties which can acquire assets. In addition, Alberta has added a holistic assessment where numerous factors are considered to determine whether a licensee poses an unreasonable risk.

In Texas, each operator of a well must file a bond, letter of credit, or cash deposit with the RRC. The amount of the bond, letter of credit or deposit varies by number and type of wells, but is not dependent upon the financial capacity of the operator.

Environmental Regulation

The oil and natural gas industry is currently subject to stringent environmental regulation pursuant to a variety of municipal, provincial, state and federal controls, laws, and regulations governing the spill, release or emission of materials into the environment, or otherwise relating to environmental protection, all of which is subject to governmental review and revision from time to time. Such controls, laws and regulations, among other things, require the acquisition of permits or other approvals to conduct drilling and other regulated activities; restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling and production activities; limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; impose specific safety and health criteria addressing worker protection; and impose substantial liabilities for pollution resulting from drilling and production operations. In addition, controls, laws and regulations set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such controls, laws and regulations can require significant expenditures and a breach of such requirements

may result in suspension or revocation of necessary licenses and authorizations, remedial obligations, civil liability and the imposition of material administrative, civil and criminal penalties.

Environmental legislation in the Province of Alberta is, for the most part, set out in the Environmental Protection and Enhancement Act and the Oil and Gas Conservation Act, which impose strict environmental standards with respect to releases of effluents and emissions, including monitoring and reporting obligations, and impose significant penalties for non-compliance. Environmental legislation in the Province of Saskatchewan is, for the most part, set out in the Environmental Management and Protection Act, 2002 and the Oil and Gas Conservation Act, which regulate harmful or potentially harmful activities and substances, any release of such substances, and remediation obligations.

In the United States, environmental regulation is administered by numerous agencies under multiple statutes, as amended from time to time. The environmental and occupational health and safety agencies that most significantly affect our operations include the Federal Environmental Protection Agency ("**EPA**"), the Texas Commission on Environmental Quality ("**TCEQ**") and the RRC.

The EPA regulates activities that could affect human health and the environment. It derives its authority from a long list of Acts of Congress, including the Clean Water Act, the Clean Air Act, the Oil Pollution Act, the Comprehensive Environmental Response, Compensation and Liability Ac, the Resource Conservation and Recovery Act and the Safe Drinking Water Act. The EPA establishes and strictly enforces standards for environmental pollution. At the state level in Texas, the TCEQ regulates public health and natural resources, including air, water and waste, and the RRC regulates the stewardship of oil and natural gas resources, along with some aspects of environmental protection and safety related to extraction of those resources. The RRC regulations establish environmental remediation and reporting criteria for the cleanup of oil and produced water spills.

Climate Change Regulation and Litigation

Canada and the United States are signatories to the United Nations Framework Convention on Climate Change (the " **UNFCCC**") and are participants in the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing GHG emissions). Both governments also signed the Paris Agreement in December 2015, which included a commitment to keep any increase in global temperatures below two degrees Celsius. To deliver on these long-term commitments, nations establish reduction targets through Nationally Determined Contributions. Under the Trump administration the United States withdrew from the Paris Agreement in 2017 and subsequently rejoined under the Biden administration in 2021. In 2021, Canada and the United States joined over 90 other countries in the Global Methane Pledge which aims to reduce global methane emissions 30% below 2020 levels by 2030.

Canada's climate plan includes a target to cut GHG emissions by 40-45% from 2005 levels by 2030 and a commitment to reaching net zero emissions by 2050 has been legislated. A number of policy measures have been put in place to assist in achieving these targets. Canadian provincial and federal carbon pricing regulations and methane regulations, have financial and operating impacts on our Canadian business segment.

The United States has committed to reducing GHG emissions by 50-52% from 2005 levels by 2030 and reaching net zero by 2050. Methane regulations have been proposed with future policies aimed to reduce methane emissions including those from oil and gas operations.

Carbon Pricing

In 2019, the Government of Canada implemented the federal Greenhouse Gas Pollution Pricing Act. The Act established a federal benchmark carbon pollution pricing system applied to fuel and combustible waste. The enacted federal carbon pricing impacts provincial jurisdictions that do not have an equivalent Output-Based Pricing System in place. The Provinces of Saskatchewan and Alberta, where Baytex operates, have performance standards in place which determine our financial exposure to the federal fuel

tax. Both provinces have obtained and must maintain federal equivalency for their programs. These provincial programs have associated compliance costs when performance standards, relative to an emissions benchmark, cannot be fully met. Compliance costs differ by province depending on the performance standard requirement and compliance cost rate.

Carbon pricing in Canada is currently set to escalate from $40 per tonne of CO_2e (tCO_2e) in 2021 and will rise to $50 per tCO_2e in 2022. The government has confirmed an escalation of $15 per tCO_2e annually to $170 per tCO_2e by 2030. There are direct costs of compliance fees in the performance standards, as well as inflationary influences on the cost of services and products as carbon pricing increases fuel costs for service providers. Registering our facilities in provincial performance standards limits the financial exposure of compliance fees.

In the Province of Saskatchewan, the Output-Based Performance Standard regulation applies to facilities emitting more than 25,000 tCO_2e. We have elected to register our Kerrobert SAGD facility, even though it is under this threshold. The remainder of our facilities in Saskatchewan do not meet the large emitter criteria; however, we have opted into this provincial regulation by aggregating all of our other operated facilities and as a result our operated facilities are not subject to the federal carbon pollution pricing system. This provincial program requires an annual 1.25% reduction in stationary combustion emission escalating to a total 15% reduction by 2030 when compared to a 2019 baseline. To the extent a company does not meet the required reduction, annual compliance fees apply to the excess regulated emissions. At a minimum the province matches the federal carbon pricing schedule and applies this price to the excess emissions.

In the Province of Alberta, the Technology Innovation and Emission Reduction regulation applies to facilities that emit more than 100,000 tCO_2e. None of our facilities meet these criteria; however, we chose to opt into this provincial regulation by aggregating our operated facilities and as a result our operated facilities are not subject to the federal carbon pollution pricing system. The Alberta regulation requires an immediate 10% reduction from a 2020 benchmark. To the extent a company does not meet the required reduction, annual compliance fees apply to the excess regulated emissions. At a minimum the province matches the federal carbon pricing schedule and applies this price to the excess emissions.

Methane Regulations

In 2018, Environment and Climate Change Canada set in place federal regulations for methane emissions from the oil and gas sector which came into force January 1, 2020. These regulations are set to achieve a methane reduction from upstream oil and gas facilities of 40-45% below 2012 levels by 2025. The Provinces take responsibility for energy and natural resources within their boundaries and have bodies to govern these activities. The Provinces of Alberta and Saskatchewan have developed GHG emissions reduction programs of their own, that have achieved equivalency under the federal regulations. These programs have increasing regulatory stringency in subsequent years and, if specified climate-related outcomes are not met, additional regulations could come into force. In October 2021, the government of Canada committed to expanding its oil and gas methane emissions reduction target to at least a 75% reduction below 2012 levels by 2030.

Tightening methane regulations in future years may require retrofitting existing sites, equipment upgrades, GHG reduction project planning, capital investment, air monitoring and other reporting requirements. Additional future costs will be associated with equipment, projects, monitoring and reporting. We continue to monitor ongoing developments and proposed regulations to ensure regulatory compliance can be achieved.

Litigation

In addition, certain municipal entities and advocacy organizations have sued oil companies in the United States and threatened to sue oil companies in Canada for damage caused by climate change. Certain large oil companies have also been sued in the United States under securities laws for failing to disclose the risks associated with climate change. At this time we cannot anticipate if we will be included in any

such litigation, whether the legal theories advanced in such lawsuits will be accepted by the courts or the potential impact of any such lawsuits.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and gas industry. In addition, Canada is a signatory to the United Nations Declaration of the Rights of Indigenous Peoples ("**UNDRIP**") and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada. In December 2020, the federal government introduced Bill C-15: An Act respecting the United Nations Declaration on the Rights of Indigenous Peoples Act ("**Bill C-15**"). The intention of Bill C-15, if passed, is to establish a process whereby the Government of Canada will take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives.

Continued development of common law precedent regarding existing laws relating to Indigenous consultation and accommodation as well as the adoption of new laws such as UNDRIP and Bill C-15 are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines.

Occupational Health and Safety

The Corporation's operations must be carried out in accordance with safe work procedures, rules and policies contained in applicable safety legislation. Such legislation requires that every employer ensures the health and safety of all persons at any of its work sites and all workers engaged in the work of that employer. The legislation, which provides for incident reporting procedures, also requires every employer to ensure all of its employees are aware of their duties and responsibilities under the applicable legislation. Penalties under applicable occupational health and safety legislation include significant fines and incarceration.

General

Implementation of more stringent environmental regulations on our operations could affect the capital and operating expenditures and plans for our operations. In addition to the agencies that directly regulate oil and gas operations, there are other state and local conservation and environmental protection agencies that regulate air quality, water quality, fish, wildlife, visual quality, transportation, noise, spills, incidents and transportation.

We believe that, in all material respects, we are in compliance with, and have complied with, all applicable environmental laws and regulations. We have made and will continue to make expenditures in our efforts to comply with all environmental regulations and requirements. We consider these a normal, recurring cost of our ongoing operations and not an extraordinary cost of compliance with governmental regulations. We believe that our continued compliance with existing requirements has been accounted for and will not have a material and adverse impact on our financial condition, results of operations and operating cash flows. However, we cannot predict the passage of or quantify the potential impact of any more stringent future laws and regulations at this time.

DIVIDENDS

We do not currently pay a dividend and have not paid a dividend in any of the last three years. Any dividends declared in the future will be subject to review by the Board of Directors taking into account our prevailing financial circumstances at the relevant time and any amount distributed in the future will depend on numerous factors, including profitability, fluctuations in working capital, the timing and amount of capital expenditures, applicable law and other factors that the Board may deem relevant. In addition, we may be restricted from paying dividends by the provisions of the agreements governing our current indebtedness and any indebtedness we may incur in the future.

DESCRIPTION OF CAPITAL STRUCTURE

Share Capital

Baytex is authorized to issue an unlimited number of Common Shares without nominal or par value and 10,000,000 preferred shares, without nominal or par value, issuable in series. As at the date of this AIF, there were no preferred shares outstanding.

The following is a summary of certain provisions of the share capital of Baytex. For a complete description of the share provisions, reference should be made to the Articles of Incorporation of Baytex, a copy of which is accessible on the SEDAR website at *www.sedar.com* (filed on January 10, 2011).

Common Shares

Holders of Common Shares are entitled to notice of meetings of the holders of Common Shares and to attend the meetings and to one vote per share at such meetings (other than for meetings of a class or series of shares of the Corporation other than the Common Shares).

Holders of Common Shares will be entitled to receive dividends as and when declared by the Board, subject to prior satisfaction of all preferential rights to dividends attached to shares of other classes of shares of the Corporation ranking in priority to the Common Shares in respect of dividends.

Holders of Common Shares will be entitled in the event of any liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or any other distribution of the assets of the Corporation among its shareholders for the purpose of winding-up its affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of the Corporation ranking in priority to the Common Shares in respect of return of capital on dissolution, to share rateably, together with the holders of shares of any other class of shares of the Corporation ranking equally with the Common Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution.

Preferred Shares

Preferred Shares may be issued from time to time in one or more series, each series to consist of such number of shares as a may be authorized by the Board, and subject to the provisions of the ABCA, the Board may fix the rights, restrictions, privileges, conditions and designations attached to each series of Preferred Shares. The Preferred Shares shall be entitled to preference over the Common Shares and any other shares of the Corporation ranking junior to the Preferred Shares with respect to payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, to the extent fixed in the case of each respective series, and may also be given such other preferences over the Common Shares and any other shares of the Corporation ranking junior to the Preferred Shares as may be fixed in the case of each such series.

Senior Notes

On June 6, 2014 we issued US$400 million of 5.625% notes due June 1, 2024. The 2024 Notes pay interest semi-annually and are redeemable at the Company's option, in whole or in part, commencing on June 1, 2019 at the redemption prices specified in the 2014 Debt Indenture. Only US$200 million principal amount of these notes were outstanding as at December 31, 2021.

On February 5, 2020 we issued US$500 million of 8.75% senior unsecured notes due April 1, 2027. The 2027 Notes pay interest semi-annually and are redeemable at the Company's option, in whole or in part, commencing on April 1, 2023 at the redemption prices specified in the 2020 Debt Indenture.

For a complete description of the Senior Notes, reference should be made to the applicable debt indenture, copies of which are accessible on *www.sedar.com*. See *"Material Contracts"*.

Credit Facilities

Our Credit Facilities consist of the Revolving Facilities and the Term Loan. The Revolving Facilities total US$575 million and consist of: (i) a US$50 million operating loan and a US$325 million syndicated revolving loan for Baytex and (ii) a US$200 million syndicated revolving loan for Baytex USA. The Revolving Facilities are secured and have an extendible four-year term that, unless extended by the lenders, will mature on April 2, 2024. The Term Loan is a $300 million syndicated loan for Baytex Energy Limited Partnership. The Term Loan is with the same syndicate of lenders as the Revolving Facilities and also matures on April 2, 2024

For additional details regarding the covenants in our Credit Facilities and our compliance therewith, see our MD&A for the year ended December 31, 2021. Also see *"Material Contracts"*.

RATINGS

The following information relating to our credit ratings is provided as it relates to our financing costs, liquidity and operations. Specifically, credit ratings affect our ability to obtain short-term and long-term financing and the cost of such financing. A reduction in our current credit ratings by the rating agencies, particularly a downgrade below the current ratings or a negative change in the ratings outlook, could adversely affect our cost of financing and our access to sources of liquidity and capital. In addition, changes in credit ratings may affect our ability and the associated costs to (i) enter into ordinary course derivative or hedging transactions and may require us to post additional collateral under certain of our contracts, and (ii) enter into and maintain ordinary course contracts with customers and suppliers on acceptable terms.

Credit Ratings Received as at the date of this AIF

	S&P Global Ratings ("**S&P**")	Moody's Investors Service ("**Moody's**")	Fitch Ratings ("**Fitch**")
Issuer Credit Rating	B	B2	B
Senior Unsecured Debt (Senior Notes)	B+	B3	B

S&P's credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. According to the S&P rating system, debt rated "B" is more vulnerable to nonpayment than obligations rated 'BB', but the obligor currently has the capacity to meet its financial commitments on the obligation. Adverse business, financial, or economic conditions will likely impair the obligor's capacity or willingness to meet its financial commitments on the obligation. The ratings from AA to CCC may be modified by the addition of a plus (+) or a minus (-) sign to show relative standing within the major rating categories. In addition, S&P may add a rating outlook of "positive", "negative" or "stable" which assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years).

Moody's credit ratings are on a long-term debt rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. According to the Moody's rating system, securities rated "B" are considered speculative and are subject to high credit risk. Moody's appends numerical modifiers 1, 2 and 3 to each generic rating classification from Aa through C. The modifier 1 indicates that the security ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of its generic rating category. In addition, Moody's may add a rating outlook of "positive", "negative", "stable" or "developing" which assess the likely direction of an issuers rating over the medium term.

Fitch's issuer credit ratings are on a rating scale that ranges from AAA to D which represents the range from highest to lowest quality. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show the relative standing within the major rating categories. An issuer credit rating of "B" by Fitch is within the sixth highest of eleven categories and indicates that material default risk is present, but a limited margin of safety remains. Financial commitments are currently being met; however, capacity for continued payment is vulnerable to deterioration in the business and economic environment. Fitch's "stable" outlook indicates a low likelihood of a rating change over a one to two year period. Fitch's ratings of individual securities are on a rating scale that ranges from AAA to C, which represents the highest to lowest quality of such securities rated. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show the relative standing within the major rating categories.

The credit ratings accorded to Baytex by S&P, Moody's and Fitch are not recommendations to purchase, hold or sell any of our securities inasmuch as such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

We have made payments to S&P, Moody's and Fitch in connection with the assignment of ratings to our long-term debt and may make payments to S&P, Moody's and Fitch in the future in connection with the confirmation of such ratings for purposes of the offering of debt securities.

MARKET FOR SECURITIES

The Common Shares are listed and trade on the TSX under the symbol "BTE". The following tables set forth the price range and trading volume of the Common Shares on the TSX and on all Canadian Exchanges ('Composite') for the periods indicated.

	Canada TSX Trading			Canada Composite Trading		
	Price Range			Price Range		
	High ($)	Low ($)	Volume Traded	High ($)	Low ($)	Volume Traded
2021						
January	0.92	0.69	98,908,789	0.92	0.69	168,343,607
February	1.39	0.76	144,911,475	1.39	0.76	268,364,721
March	1.53	1.24	113,123,972	1.54	1.23	244,655,568
April	1.52	1.23	51,487,694	1.52	1.23	114,260,654
May	2.00	1.48	80,961,362	2.00	1.48	172,486,984
June	2.51	1.98	92,803,357	2.51	1.98	205,508,332
July	2.59	1.75	72,840,616	2.59	1.75	152,757,992
August	2.24	1.87	60,539,781	2.24	1.87	152,449,604
September	3.59	2.13	129,102,282	3.59	2.13	271,204,341
October	4.32	3.46	100,941,732	4.32	3.46	217,069,407
November	4.39	3.51	130,012,072	4.39	3.51	254,935,948
December	4.02	3.21	158,272,420	4.02	3.21	281,822,045

DIRECTORS AND OFFICERS

Directors of the Corporation

The following table sets forth the name, municipality of residence, age as at December 31, 2021, year of appointment as a director of the Corporation and principal occupation for each of the directors of the Corporation.

Name and Municipality of Residence	Age	Director Since	Principal Occupation for Past Five Years
Mark R. Bly [1] Incline Village, Nevada	62	November 2017	Independent businessman.
Trudy M. Curran [2][4] Calgary, Alberta	59	July 2016	Independent businesswoman. Interim CEO and managing director of Riversdale Resources from February 2019 to June 2019.
Don G. Hrap [3][5] Houston, Texas	62	March 2020	Independent businessman. Formerly served in senior leadership roles with ConocoPhillips from 2009-2018, most recently as President, Lower 48 and, prior to that, President Lower 48 and Latin America and Senior Vice President of Western Canada Gas.
Edward D. LaFehr Calgary, Alberta	62	May 2017	President and Chief Executive Officer of the Corporation since May 2017, previously President of the Corporation since July 2016.
Jennifer A. Maki [2][5] North York, Ontario	51	September 2019	Independent businesswoman. Formerly CEO of Vale Canada and Executive Director of Vale-SA-Base Metals from November 2014 until December 2017.
Greg Melchin [4][5] Calgary, Alberta	68	May 2008	Independent businessman.
David L. Pearce [2][3] Calgary, Alberta	67	August 2018	Deputy Managing Partner, Azimuth Capital Management.
Stephen D.L. Reynish [3][4] Calgary, Alberta	63	November 2020	President and Chief Executive Officer of Enlighten Innovations. Formerly Executive Vice President at Suncor Energy Inc. from 2012 until 2020.

Notes:

(1) Chair of the Board and *ex officio* member of all board committees to which he is not appointed.
(2) Member of our Human Resources and Compensation Committee.
(3) Member of our Reserves and Sustainability Committee.
(4) Member of our Nominating and Governance Committee.
(5) Member of our Audit Committee.

Officers of the Corporation

The following table sets forth the name, municipality of residence, age as at December 31, 2021, position held with the Corporation and principal occupation of each of the officers of the Corporation.

Name and Municipality of Residence	Age	Office	Principal Occupation for Past Five Years
Edward D. LaFehr Calgary, Alberta	62	President and Chief Executive Officer	President, Chief Executive Officer and a Director of the Corporation since May 2017 and President of the Corporation since July 2016.
Rodney D. Gray Calgary, Alberta	50	Executive Vice President and Chief Financial Officer	Executive Vice President and Chief Financial Officer of the Corporation since August 2018. Prior thereto, Chief Financial Officer of the Corporation since April 2014.
Chad E. Lundberg Calgary, Alberta	40	Chief Operating & Sustainability Officer	Chief Operating & Sustainability Officer since July 2021. Prior thereto Vice President, Light Oil since December 2018. Prior thereto Vice President, Viking Business unit of the Corporation since August 2018, Vice President, Operations of Raging River Exploration Inc. from October 2016 until August 2018.
Kendall D. Arthur Calgary, Alberta	41	Vice President, Heavy Oil	Vice President, Heavy Oil of the Corporation since December 2018. Prior thereto, a business unit Vice President with the Corporation since January 2012.
Brian G. Ector Calgary, Alberta	53	Vice President, Capital Markets	Vice President, Capital Markets of the Corporation since August 2018. Prior thereto, an officer of the Corporation since June 2011.
Nicole Frechette Calgary, Alberta	38	Vice President, Light Oil	Vice President, Light Oil since February 2022. Prior thereto Subsurface Manager, Light Oil since August 2021 and various senior technical and leadership roles with Repsol and Talisman Energy from 2005 until August 2021.
Chad L. Kalmakoff Calgary, Alberta	45	Vice President, Finance	Vice President, Finance of the Corporation since September 2015.
M. Scott Lovett Calgary, Alberta	48	Vice President, Corporate Development	Vice President, Corporate Development of the Corporation since September 2017. Prior thereto, Executive Vice President, Business Development with Eagle Energy Inc. from September 2014 until August 2017.
James Maclean Calgary, Alberta	42	Vice President, General Counsel and Corporate Secretary	Vice President, General Counsel and Corporate Secretary since February 2022. Prior thereto General Counsel and Corporate Secretary since August 2018 and various legal roles with the Corporation since May 2014.

Ownership of Securities by Management

As at March 1, 2022, the directors and officers of Baytex, as a group, beneficially owned, or controlled or directed, directly or indirectly, 4,247,384 Common Shares.

Corporate Cease Trade Orders or Bankruptcies

To the Corporation's knowledge, no director or executive officer of Baytex (nor any personal holding company of any of such persons) is, as of the date of this AIF, or was within ten years before the date of this AIF, a director, chief executive officer or chief financial officer of any company (including Baytex), that was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**") that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer or was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Other than as disclosed below, to the Corporation's knowledge, no director or executive officer of Baytex (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of our securities to materially affect control of us, is, as of the date of this AIF, or has been within the ten years before the date of this AIF, a director or executive officer of any company (including Baytex) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver-manager or trustee appointed to hold its assets or has, within the ten years before the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver-manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Mr. Pearce, a director of Baytex, is a director of Kaisen Energy Corp. (a private oil and gas production company). Kaisen made a proposal under the *Canada Business Corporations Act* on December 8, 2021.

Penalties or Sanctions

To the Corporation's knowledge, no director or executive officer of Baytex (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of our securities to materially affect control of us, has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts

There are potential conflicts of interest to which the directors and officers of Baytex will be subject in connection with the operations of Baytex. In particular, certain of the directors and officers of Baytex are involved in managerial or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of Baytex or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Baytex. Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director will disclose his interest in such contract or agreement and will refrain from voting on any matter in respect of such contract or agreement unless otherwise provided in the ABCA.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The text of the Audit Committee's Mandate and Terms of Reference is attached as Appendix C.

Composition of the Audit Committee

The members of our Audit Committee are Jennifer A. Maki, Don G. Hrap and Gregory K. Melchin, each of whom is independent and financially literate within the meaning of National Instrument 52-110.

In addition, the Board has determined that Ms. Maki and Mr. Melchin are “Audit Committee Financial Experts” pursuant to the SEC’s definition of the term.

The relevant education and experience of each Audit Committee member is outlined below:

Name	Relevant Education and Experience
Jennifer A. Maki *Committee Chair*	Bachelor of Commerce degree from Queen's University and a postgraduate diploma from the Institute of Chartered Accountants of Ontario. Formerly served as CEO of Vale Canada and Executive Director of Vale-SA-Base Metals. Prior thereto, CFO and Executive Vice President, of Vale-SA-Base Metals. Before joining Vale/Inco, worked at PricewaterhouseCoopers LLP for 10 years.
Don G. Hrap	Bachelor of Science in Mechanical Engineering and a Master in Business Administration. From 2009-2018, he served as President, Lower 48 at ConocoPhillips with strong breadth and depth of experience across several U.S. oil resource plays. Prior to this at ConocoPhillips, Mr. Hrap was senior vice president of Western Canada Gas. He joined ConocoPhillips in 2006 through the merger with Burlington Resources, serving as senior vice president of operations for Burlington Canada. Earlier, he was vice president for the North American Division at Gulf Canada Resources, where he worked for 17 years.
Gregory K. Melchin	Bachelor of Science degree (major in accounting) and a Fellow Chartered Accountant designation from the Institute of Chartered Accountants of Alberta. Also completed the Directors Education Program with the Institute of Corporate Directors. Member of the Legislative Assembly of Alberta from March 1997 to March 2008. Prior to being elected to the Legislative Assembly of Alberta, served in various management positions for 20 years in the Calgary business community.

Pre-Approval of Policies and Procedures

Although the Audit Committee has not adopted specific policies and procedures for the engagement of non-audit services by our auditors, it does pre-approve all non-audit services to be provided to us and our subsidiaries by the external auditors. The pre-approval for recurring services, such as preliminary work on the integrated audit, securities filings, translation of our financial statements and related MD&A into the French language and tax and tax-related services, is provided on an annual basis and other services are subject to pre-approval as required.

External Auditor Service Fees

The following table provides information about the fees billed to us and our subsidiaries for professional services rendered by our external auditors, during fiscal 2021 and 2020:

Year	Audit Fees [1]	Audit-Related Fees [2]	Tax Fees [3]	All Other Fees [4]	Total
2021	$ 989	$ —	$ —	$ —	$ 989
2020	$ 1,083	$ —	$ —	$ —	$ 1,083

Notes:

(1) Audit fees consist of fees for the audit of our annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements. In addition to the fees for annual audits of financial statements and review of quarterly financial statements, services in this category for fiscal 2021 and 2020 also include amounts for audit work performed in relation to the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 relating to internal control over financial reporting.

(2) Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of our financial statements and are not reported as Audit Fees.

(3) Tax fees include fees for tax compliance, tax advice and tax planning.

(4) Other fees include all other non-audit services.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

In June 2016, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency (CRA) that deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. These reassessments follow the previously disclosed letter which we received in November 2014 from the CRA, proposing to issue such reassessments.

We remain confident that the tax filings of the affected entities are correct and are vigorously defending our tax filing positions. The reassessments do not require us to pay any amounts in order to participate in the appeals process.

In September 2016, we filed a notice of objection for each notice of reassessment received which will be reviewed by the Appeals Division of the CRA. An Appeals Officer was assigned to our file in July 2018, we estimate the remaining Appeals Division process could take another year. If the Appeals Division upholds the notices of reassessment, we have the right to appeal to the Tax Court of Canada; a process that we estimate could take a further two years. Should we be unsuccessful at the Tax Court of Canada, additional appeals are available; a process that we estimate could take another two years and potentially longer.

By way of background, we acquired several privately held commercial trusts in 2010 with accumulated non-capital losses of $591 million (the "Losses"). The Losses were subsequently used to reduce the taxable income of those trusts. The reassessments disallow the deduction of the Losses under the general anti-avoidance rule of the Income Tax Act (Canada). If, after exhausting available appeals, the deduction of Losses continues to be disallowed, we will owe cash taxes for the years 2012 through 2015 and an additional amount for late payment interest. The amount of cash taxes owing and the late payment interest are dependent upon the amount of unused tax shelter available to offset the reassessed income, including tax shelter from future years that may be applied to the years 2012 through 2015.

Other than the foregoing, there are no legal proceedings that we are or were a party to, or that any of our property is or was the subject of, during our most recently completed financial year, that were or are material to us, and there are no such material legal proceedings that we are currently aware of that are contemplated.

There were no: (i) penalties or sanctions imposed against us by a court relating to securities legislation or by a securities regulatory authority during our most recently completed financial year; (ii) other penalties or sanctions imposed by a court or regulatory body against us that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements we entered into with a court relating to securities legislation or with a securities regulatory authority during our most recently completed financial year.

INTEREST OF INSIDERS AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of our directors and executive officers, any holder of Common Shares who beneficially owns or controls or directs, directly or indirectly, more than 10 percent of the outstanding Common Shares, or any known associate or affiliate of such persons, in any transactions within the three most recently completed financial years or since the beginning of our last completed financial year which has materially affected or is reasonably expected to materially affect us.

TRANSFER AGENT AND REGISTRAR

Odyssey Trust Company, at its principal offices in Calgary, Alberta, Vancouver, British Columbia and Toronto, Ontario, is the transfer agent and registrar for the Common Shares in Canada. Odyssey Transfer US Inc., at its principal office in Denver, Colorado is the transfer agent and registrar for the Common Shares in the United States. Computershare Trust Company, N.A., at its principal office in Canton, Massachusetts, is the transfer agent and registrar for the 2024 Notes and the 2027 Notes.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts entered into by us within the most recently completed financial year, or before the most recently completed financial year but are still material and are still in effect, are the following:

a. the credit agreement in respect of the Revolving Credit Facilities (filed on April 13, 2016), the first amendment thereof (filed on May 2, 2018), the second amendment thereof (filed on October 12, 2018), the third amendment thereof (filed May 16, 2019), the fourth amendment thereof (filed March 9, 2020) and the fifth amendment thereof (filed December 13, 2021);

b. the credit agreement in respect of the Term Facility (filed on October 12, 2018), the first amendment thereof (filed May 16, 2019) and the second amendment thereof (filed March 9, 2020);

c. 2014 Debt Indenture (filed on June 20, 2014) and supplemental indentures thereto (filed on August 13, 2014, September 9, 2014, February 20, 2018, October 12, 2018 and December 13, 2021)

d. 2020 Debt Indenture (filed on February 10, 2020); and

e. our share award incentive plan (filed on April 18, 2016) and our subsequently amended share award incentive plan (filed on January 28, 2018 and March 1, 2022).

Copies of each of these contracts are accessible on the SEDAR website at *www.sedar.com*.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 "Continuous Disclosure Obligations" by us during, or related to, our most recently completed financial year other than McDaniel, our independent qualified reserves evaluator. None of the designated professionals of McDaniel have any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared a report, valuation, statement or opinion, at any time thereafter or to be received by them.

KPMG LLP are the auditors of the Corporation and have confirmed with respect to the Corporation, that they are independent within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations, and also that they are independent accountants with respect to the Corporation under all relevant US professional and regulatory standards.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of Baytex or of any associate or affiliate of Baytex.

ADDITIONAL INFORMATION

Additional information relating to us can be found on our website and on the SEDAR website at *www.sedar.com*. Further information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities issued and authorized for issuance under our equity compensation plans will be contained in our Information Circular - Proxy Statement for the annual meeting of Shareholders to be held April 28, 2022. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2021 and the related MD&A which are accessible on the SEDAR website at *www.sedar.com*.

For additional copies of this AIF and the materials listed in the preceding paragraph, please contact:

Baytex Energy Corp.
Suite 2800, Centennial Place, East Tower
520 – 3rd Avenue S.W.
Calgary, Alberta T2P 0R3
Phone: (587) 952-3000
Fax: (587) 952-3029
Website: *www.baytexenergy.com*

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Form 51-101F3

Management of Baytex Energy Corp. (" **Baytex**") is responsible for the preparation and disclosure of information with respect to Baytex's oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data.

Independent qualified reserves evaluators have evaluated Baytex's reserves data. The report of the independent qualified reserves evaluators is presented below.

The Reserves and Sustainability Committee of the Board of Directors of Baytex (the " **Reserves Committee**") has:

a. reviewed Baytex's procedures for providing information to the independent qualified reserves evaluators;

b. met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and

c. reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee has reviewed Baytex's procedures for assembling and reporting other information associated with oil and natural gas activities and has reviewed that information with management. The Board of Directors of Baytex has, on the recommendation of the Reserves Committee, approved:

a. the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

b. the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data; and

c. the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

(signed) *"Edward D. LaFehr"*
Edward D. LaFehr
President and Chief Executive Officer

(signed) *"Rodney D. Gray"*
Rodney D. Gray
Executive Vice President and Chief Financial Officer

(signed) *"Don G. Hrap"*

Director and Chair of the Reserves and Sustainability Committee

(signed) *"David L. Pearce"*

Director and Member of the Reserves and Sustainability Committee

March 1, 2022

APPENDIX B

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

Form 51-101F2

To the Board of Directors of Baytex Energy Corp. ("Company"):

1. We have evaluated Baytex's reserves data as at December 31, 2021. The reserves data is an estimate of proved reserves and probable reserves and related future net revenue as at December 31, 2021 estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the estimated future net revenue (before deduction of income taxes) attributed to proved + probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2021, and identifies the respective portions thereof that we have evaluated and reported on to Company's management:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation or Review Report	Location of Reserves	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) (in $ thousands)			
			Audited	Evaluated	Reviewed	Total
McDaniel & Associates	December 31, 2021	Canada	—	2,708,311	—	2,708,311
McDaniel & Associates	December 31, 2021	United States	—	2,375,441	—	2,375,441
TOTALS				5,083,752		5,083,752

6. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not evaluate.

7. We have no responsibility to update the report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report.

8. Because the reserves data is based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

(signed) *"Brian R. Hamm"*

Brian R. Hamm, P. Eng.
President & CEO

Calgary, Alberta
February 3, 2022

APPENDIX C

BAYTEX ENERGY CORP.

AUDIT COMMITTEE

MANDATE AND TERMS OF REFERENCE

ROLE AND OBJECTIVE

The Audit Committee (the "Committee") is a committee of the board of directors (the " Board") of Baytex Energy Corp. (the " Corporation") to which the Board has delegated certain of its responsibilities. The primary responsibility of the Committee is to review the interim and annual financial statements of the Corporation and to recommend their approval or otherwise to the Board. The Committee is also responsible for reviewing and recommending to the Board the appointment and compensation of the external auditors of the Corporation, overseeing the work of the external auditors, including the nature and scope of the audit of the annual financial statements of the Corporation, pre-approving services to be provided by the external auditors and reviewing the assessments prepared by management and the external auditors on the effectiveness of the Corporation's internal controls over financial reporting.

The objectives of the Committee are to:

1. assist directors in meeting their responsibilities in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;
2. facilitate communication between directors and the external auditors;
3. enhance the external auditors' independence;
4. increase the credibility and objectivity of financial reports; and
5. strengthen the role of the independent directors by facilitating in depth discussions between the Committee, management and the external auditors.

MEMBERSHIP OF THE COMMITTEE

1. The Committee shall be comprised of not less than three members all of whom are "independent" directors and "financially literate" (within the meaning of National Instrument 52-110 "Audit Committees"). The members of the Committee shall be appointed by the Board from time to time.
2. The Board shall appoint a Chair of the Committee, who shall be an independent director.
3. Any member of the Committee may be removed or replaced at any time by the Board and shall cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy shall exist on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, each member of the Committee shall hold such office until the close of the next annual meeting of shareholders of the Corporation following appointment as a member of the Committee.

MANDATE AND RESPONSIBILITIES OF THE COMMITTEE

1. It is the responsibility of the Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting. The external auditors shall report directly to the Committee.

2. It is the responsibility of the Committee to satisfy itself on behalf of the Board with respect to the Corporation's internal control systems by:

   - identifying, monitoring and mitigating business risks; and
   - ensuring compliance with legal, ethical and regulatory requirements.

3. It is a primary responsibility of the Committee to review the interim and annual financial statements of the Corporation prior to their submission to the Board for approval. The review process should include, without limitation:

   - reviewing the critical accounting policies and changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;
   - reviewing significant management judgments, estimates and assumptions that affect the application of accounting policies and their reported amounts;
   - reviewing accounting treatment of unusual or non-recurring transactions;
   - ascertaining compliance with covenants under loan agreements;
   - reviewing disclosure requirements for commitments and contingencies;
   - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
   - reviewing unresolved differences between management and the external auditors;
   - reviewing Non-GAAP financial disclosures;
   - obtaining explanations of significant variances with comparative reporting periods; and
   - determining through inquiry if there are any related party transactions and ensuring that the nature and extent of such transactions are properly disclosed.

4. The Committee is to review all public disclosure of audited or unaudited financial information by the Corporation before its release (and, if applicable, prior to its submission to the Board for approval), including the interim and annual financial statements of the Corporation, management's discussion and analysis of results of operations and financial condition, press releases and the Annual Information Form. The Committee must be satisfied that adequate procedures are in place for the review of the Corporation's disclosure of financial information and shall periodically assess the accuracy of those procedures.

5. With respect to the external auditors of the Corporation, the Committee shall:

   - recommend to the Board the appointment of the external auditors, including the terms of their engagement for the integrated audit;
   - review and approve any other services to be provided by the external auditors (including the fee for such services);

- when there is to be a change in the external auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change;
- at least annually, review the qualifications, performance and independence of the external auditor including a) review the experience and qualifications of the senior members of the external auditor's team; b) confirm with the external auditor that it is in compliance with applicable legal, regulatory and professional standards relating to auditor independence; c) review annual reports from the external auditor regarding its independence and consider whether there are any non-audit services or relationships that may affect the objectivity and independence of the external auditor and, if so, recommend to the Board of Directors of the Company take appropriate action to satisfy itself of the independence of the external auditor; and obtain and review such reports from the external auditor as may be required by applicable legal and regulatory requirements; and
- review with the external auditor any problems or difficulties the external auditor may have encountered during the provision of its audit-related services, including any restrictions on the scope of activities or access to the requested information and any significant disagreements with management.

6. Review with the external auditors (and the internal auditor if one is appointed by the Corporation) their assessment of the internal controls of the Corporation, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for the audit and, upon completion of the audit, their reports upon the financial statements of the Corporation and its subsidiaries.

7. The Committee must pre-approve all services to be provided to the Corporation or its subsidiaries by the external auditors. In pre-approving any service, the Committee shall consider the impact that the provision of such service may have on the external auditors' independence. The Committee may delegate to one or more of its members the authority to pre-approve services, provided that the member report to the Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Committee from time to time.

8. The Committee shall review the risk management policies and procedures of the Corporation used to identify, manage and control the principle business risks facing the Corporation which is to include reviewing with management:

   - foreign currency, interest rate and commodity price risk mitigation strategies, including the use of derivative financial instruments and compliance with the Corporation's Hedging Instruments Risk Management Policy;
   - the insurance coverages maintained by the Corporation;
   - any legal claims or other contingency, including tax assessments that could have a material effect on the financial position or operation results of the Corporation; and
   - the adequacy of the security measures that are in place in respect of the Corporation's information systems and the information technology utilized by the Corporation.

9. The Committee shall establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters and the confidential, anonymous submission by employees of the Corporation and its subsidiary entities of concerns regarding questionable accounting or auditing matters.

10. The Committee shall review and approve the Corporation's hiring policies regarding employees and former employees of the present and former external auditors of the Corporation.

11. The Committee shall have the authority to investigate any financial activity of the Corporation. All employees of the Corporation and its subsidiary entities are to cooperate as requested by the Committee.

12. The Committee shall forthwith report the results of meetings and reviews undertaken and any associated recommendations to the Board.

13. The Committee shall meet with the external auditors at least four times per year (in connection with their review of the interim and annual financial statements) and at such other times as the external auditors and the Committee consider appropriate.

MEETINGS AND ADMINISTRATIVE MATTERS

1. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the chairman of the meeting shall be entitled to a second or casting vote.

2. The Chair shall preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee present shall designate from among the members present a chairman for purposes of the meeting.

3. A quorum for meetings of the Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing the Board unless otherwise determined by the Committee or the Board.

4. Meetings of the Committee should be scheduled to take place at least four times per year and at such other times as the Chair may determine.

5. Agendas, approved by the Chair, shall be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

6. The Committee may invite those officers, directors and employees of the Corporation and its subsidiary entities as it may see fit from time to time to attend at meetings of the Committee and assist thereat in the discussion and consideration of the matters being considered by the Committee, provided that the Chief Financial Officer of the Corporation shall attend all meetings of the Committee, unless otherwise excused from all or part of any such meeting by the chairman of the meeting.

7. Minutes of the Committee's meetings will be recorded and maintained and made available to any director who is not a member of the Committee upon request.

8. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation.

9. Any issues arising from the Committee's meetings that bear on the relationship between the Board and management should be communicated to the Executive Chairman or the Lead Independent Director, as applicable, by the Committee Chair.

10. At least annually, the Committee shall, in a manner it determines to be appropriate, review and assess the adequacy of its mandate and recommend to the Board of Directors any improvements to this mandate that the Committee determines to be appropriate.

Approved by the Board of Directors on April 29, 2021

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 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	12		
Basic		**$ 2.86**	$ (4.35)
Diluted		**$ 2.82**	$ (4.35)
Weighted average common shares	12		
Basic		**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.

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.

	Canada		U.S.		Corporate		Consolidated	
Years Ended December 31	**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
	$ 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 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
	$ 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

At December 31, 2020, the Company estimated the recoverable amount of each of itssix 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 itssix 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:

(000s)	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		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL					
Financial Derivatives	**$ 8,654**	**$ 8,654**	$ 5,057	$ 5,057	Level 2
Total	**$ 8,654**	**$ 8,654**	$ 5,057	$ 5,057	
Amortized cost					
Trade and other receivables	**$ 173,409**	**$ 173,409**	$ 107,477	$ 107,477	—
Total	**$ 173,409**	**$ 173,409**	$ 107,477	$ 107,477	
Financial Liabilities					
FVTPL					
Financial Derivatives	**$ (134,020)**	**$ (134,020)**	$ (26,792)	$ (26,792)	Level 2
Total	**$ (134,020)**	**$ (134,020)**	$ (26,792)	$ (26,792)	
Amortized cost					
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 $0.4 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 it's current financial position and to evaluate existing sources of liquidity. Baytex also uses Net Debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations.

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

	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

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

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

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

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

BAYTEX ENERGY CORP.

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

2021 ANNUAL HIGHLIGHTS

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

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

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

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

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

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

GUIDANCE

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

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

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

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

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

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

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

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

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

RESULTS OF OPERATIONS

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

Production

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

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

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

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

Commodity Prices

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

Crude Oil

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

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

Prices for Canadian oil trade at a discount to WTI due to a lack of egress to diversified markets from Western Canada. Differentials for Canadian oil prices relative to WTI fluctuate from period to period based on production and inventory levels in Western Canada.
We compare the price received for our light oil production in Canada to the Edmonton par benchmark oil price. The Edmonton par price averaged $80.23/bbl for 2021 compared to $45.34/bbl for 2020. Edmonton par traded at a US$3.92/bbl discount to WTI in 2021 which is tighter than a discount of US$5.60/bbl for 2020 as a result of incremental egress with the Line 3 expansion and higher demand for Canadian light oil.

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

Natural Gas

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

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

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

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

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

	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.

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

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

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

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

(1) Based on the weighted average price per unit for the period.
(2) Producer 3-way option consists of a sold call, a bought put and a sold put. To illustrate, in a US$50.00/US$60.00/US$70.00 contract, Baytex receives WTI plus US$10.00/bbl when WTI is at or below US$50.00/bbl; Baytex receives US$60.00/bbl when WTI is between US$50.00/bbl and US$60.00/bbl; Baytex receives the market price when WTI is between US$60.00/bbl and US$70.00/bbl; and Baytex receives US$70.00/bbl when WTI is above US$70.00/bbl.
(3) Contracts entered subsequent to December 31, 2021.

Operating Netback

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

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

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

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

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

General and Administrative Expense

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

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

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

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

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

Financing and Interest Expense

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

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

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

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

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

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

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

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

Exploration and Evaluation Expense

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

Depletion and Depreciation

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

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

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

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

Impairment

2021 Impairment Reversals

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

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

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

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

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

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

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

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

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

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

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

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

2020 Impairments

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

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

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

Share-Based Compensation Expense

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

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

Foreign Exchange

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

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

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

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

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

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

Net Income (Loss)

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

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

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

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

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

Other Comprehensive Income (Loss)

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

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

Capital Expenditures

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

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

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

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

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

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

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

CAPITAL RESOURCES AND LIQUIDITY

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

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

The capital intensive nature of our operations requires the maintenance of adequate sources of liquidity to fund ongoing exploration and development. Our capital resources consist primarily of adjusted funds flow, available credit facilities and proceeds received from the divestiture of oil and gas properties. Management of debt levels is a priority for Baytex in order to sustain operations and support long-term plans. At December 31, 2021, net debt[1] of $1.41 billion was $437.9 million lower than $1.85 billion at December 31, 2020. The decrease in net debt is primarily a result of free cash flow[2] of $421.3 million generated during 2021 being allocated to debt repayment.

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

Credit Facilities

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

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

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

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

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

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

Financial Covenants

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

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

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

Long-Term Notes

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

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

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

Shareholders' Capital

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

Contractual Obligations

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

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

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

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

FOURTH QUARTER OPERATING AND FINANCIAL RESULTS

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

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

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

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

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

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

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

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

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

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

QUARTERLY FINANCIAL INFORMATION

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

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

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

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

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

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

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

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

ENVIRONMENTAL REGULATIONS

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

Reporting Regulations

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

OFF BALANCE SHEET TRANSACTIONS

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

CRITICAL ACCOUNTING ESTIMATES

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

Reserves

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

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

Cash-generating Units ("CGUs")

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

Identification of Impairment and Impairment Reversal Indicators

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

Measurement of Recoverable Amount

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

Exploration and Evaluation ("E&E") Assets

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

Asset Retirement Obligations

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

Income Taxes

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

NYSE LISTING

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

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

SPECIFIED FINANCIAL MEASURES

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

Non-GAAP Financial Measures

Total sales, net of blending and other expense

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

Operating netback

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

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

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

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

Free cash flow

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

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

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

Non-GAAP Financial Ratios

Heavy oil, net of blending and other expense per bbl

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

Total sales, net of blending and other expense per boe

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

Average royalty rate

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

Operating netback per boe

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

Capital Management Measures

Net debt

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

The following table summarizes our calculation of net debt.

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

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

Adjusted funds flow

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

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

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

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

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

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

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

Internal Control Over Financial Reporting

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

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

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

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

Changes in Internal Control over Financial Reporting

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

SELECTED ANNUAL INFORMATION

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

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

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

FORWARD-LOOKING STATEMENTS

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

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

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

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

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

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

RISK FACTORS

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

Risks Relating to Our Business and Operations

Volatility of oil and natural gas prices and price differentials

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

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

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

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

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

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

Regulatory and Policy Initiatives

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

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

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

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

Physical Risk

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Public perception and its influence on the regulatory regime

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

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

Operations

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

Environment

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

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

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

Foreign Investment and Competition Act Legislation

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Our information technology systems are subject to certain risks

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

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

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

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

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

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

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

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

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

Indigenous Claims

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

Expansion into New Activities

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

Risks Related to Ownership of our Securities

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

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

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

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

Certain Risks for United States and other non-resident Shareholders

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

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

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

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

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

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

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

There is additional taxation applicable to non-residents

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

Exhibit 99.4

CERTIFICATION PURSUANT TO RULE 13a-14 OR 15d-14 OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Edward D. LaFehr, certify that:

1. I have reviewed this annual report on Form 40-F of Baytex Energy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c. Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated: March 1, 2022 BAYTEX ENERGY CORP.

/s/ *Edward D. LaFehr*
Name: Edward D. LaFehr
Title: President and Chief Executive Officer

Exhibit 99.5

CERTIFICATION PURSUANT TO RULE 13a-14 OR 15d-14 OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Rodney D. Gray, certify that:

1. I have reviewed this annual report on Form 40-F of Baytex Energy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c. Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated: March 1, 2022 BAYTEX ENERGY CORP.

/s/ *Rodney D. Gray*
Name: Rodney D. Gray
Title: Executive Vice President and Chief Financial Officer

Exhibit 99.6

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Baytex Energy Corp. (the "Company") on Form 40-F for the fiscal year ended December 31, 2021, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Edward D. LaFehr, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 1, 2022 BAYTEX ENERGY CORP.

/s/ *Edward D. LaFehr*
Name: Edward D. LaFehr
Title: President and Chief Executive Officer

Exhibit 99.7

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Baytex Energy Corp. (the "Company") on Form 40-F for the fiscal year ended December 31, 2021, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Rodney D. Gray, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 1, 2022 BAYTEX ENERGY CORP.

/s/ *Rodney D. Gray*
Name: Rodney D. Gray
Title: Executive Vice President and Chief Financial Officer

Exhibit 99.8

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Baytex Energy Corp.:

We consent to the use of our reports, each dated February 24, 2022, with respect to the consolidated financial statements and the effectiveness of internal control over financial reporting included in this Annual Report on Form 40-F.

/s/ KPMG LLP

Chartered Professional Accountants

Calgary, Canada

March 1, 2022

Exhibit 99.9

CONSENT OF INDEPENDENT ENGINEERS

We refer to our report dated February 3, 2022 and effective December 31, 2021, evaluating the proved and probable petroleum and natural gas reserves attributable to Baytex Energy Corp. and its affiliates (collectively, the "Company"), which is entitled "Baytex Energy Corp., Evaluation of Petroleum Reserves, based on Forecast Prices and Cost, As of December 31, 2021" (the "Report").

We hereby consent to the references to our name in the Company's Annual Report on Form 40-F to be filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended, and to the incorporation by reference in Registration Statements No. 333-171568 on Form S-8 of the Company and to the use of the Report.

We also confirm that we have read the Company's Annual Information Form for the year ended December 31, 2021 dated March 1, 2022, and that we have no reason to believe that there are any misrepresentations in the information contained therein that was derived from the Report or that is within our knowledge as a result of the services we performed in connection with such Report.

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

/s/ *Brian R. Hamm*

Brian R. Hamm, P. Eng.
President and CEO

Calgary, Alberta, Canada
March 1, 2022

Baytex Energy Corp.
Supplemental Disclosures about Extractive Activities - Oil and Gas (unaudited)
December 31, 2021

Exhibit 99.10

The following disclosures have been prepared by Baytex Energy Corp. (“Baytex” or the “Company”) in accordance with Accounting Standards Codification 932 “Extractive Activities - Oil & Gas” (“ASC 932”) issued by the Financial Accounting Standards Board. The standard requires the use of a 12 month average price to estimate proved reserves calculated as the unweighted arithmetic average of first-day-of-the-month prices within the 12 month period prior to the end of the reporting period.

Petroleum and Natural Gas Reserves Information

Users of this information should be aware that the process of estimating quantities of "proved developed" and "proved undeveloped" crude oil, natural gas liquids, bitumen and natural gas is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures. Future fluctuations in prices and costs, production rates, or changes in political or regulatory environments could cause the Company's reserves to be materially different from that presented.

Proved petroleum and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids (“NGL”) that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved developed petroleum and natural gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods, which may require future expenditures.

Proved undeveloped petroleum and natural gas reserves are reserves that are expected to be recovered from known accumulations where a future expenditure is required.

Proved reserves and production volumes are presented net of royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. Figures reported as natural gas reserves and production volumes do not include flared gas, injected gas or gas consumed in operations. All natural gas reserves and production volumes presented are sales volumes. Undrilled locations underlying the estimates of our proved undeveloped reserves as of December 31, 2020 and 2021 are included in a development plan that was adopted by Baytex for the applicable year as a result of our annual long-range planning process and associated corporate financial model and all such locations were scheduled to be drilled within five years of the initial development plan adoption date.

The changes in Baytex's net proved crude oil, NGL, bitumen and natural gas reserves under constant prices and costs for the two-year period ended December 31, 2021 were as follows:

	Canada				United States			
	Crude Oil (mbbl)	**NGL** (mbbl)	**Bitumen** (mbbl)	**Natural Gas** (mmcf)	**Crude Oil** (mbbl)	**NGL** (mbbl)	**Bitumen** (mbbl)	**Natural Gas** (mmcf)
Net proved reserves								
December 31, 2019	96,879	2,804	11,136	70,188	37,685	53,675	—	165,363
Revisions of previous estimates	(49,515)	(892)	(8,251)	(11,898)	449	(2,736)	—	(794)
Improved recovery	—	—	—	—	—	—	—	—
Purchases of minerals in place	7	—	—	8	—	—	—	—
Extensions and discoveries	1,092	516	2,824	10,364	486	446	—	1,550
Production	(12,812)	(384)	(825)	(14,271)	(3,493)	(2,992)	—	(11,530)
Sales of minerals in place	(13)	—	—	(23)	—	—	—	—
December 31, 2020	35,639	2,044	4,883	54,367	35,127	48,393	—	154,589
Revisions of previous estimates	28,031	729	175	31,805	1,393	250	—	5,583
Improved recovery	—	—	—	—	—	—	—	—
Purchases of minerals in place	57	—	—	—	—	—	—	—
Extensions and discoveries	37,694	3,223	—	42,652	2,128	2,799	—	10,180
Production	(11,977)	(580)	(568)	(16,973)	(3,819)	(2,736)	—	(10,187)
Sales of minerals in place	(12)	(17)	—	(486)	(14)	(5)	—	(25)
December 31, 2021	89,431	5,400	4,490	111,364	34,814	48,701	—	160,140
Net proved developed reserves								
End of year 2019	47,577	1,179	9,286	44,537	16,119	23,906	—	71,748
End of year 2020	20,749	1,616	808	37,858	15,809	21,277	—	67,187
End of year 2021	41,918	2,184	592	68,498	18,750	22,334	—	72,257

Baytex Energy Corp.
Supplemental Disclosures about Extractive Activities - Oil and Gas (unaudited)
December 31, 2021

	Canada				United States			
	Crude Oil (mbbl)	NGL (mbbl)	Bitumen (mbbl)	Natural Gas (mmcf)	Crude Oil (mbbl)	NGL (mbbl)	Bitumen (mbbl)	Natural Gas (mmcf)
Net proved undeveloped reserves								
End of year 2019	49,302	1,625	1,850	25,651	21,566	29,769	—	93,615
End of year 2020	14,889	428	4,075	16,508	19,318	27,116	—	87,402
End of year 2021	47,513	3,216	3,898	42,866	16,064	26,368	—	87,882

	Total				
	Crude Oil (mbbl)	NGL (mbbl)	Bitumen (mbbl)	Natural Gas (mmcf)	Total (mboe)
Net proved reserves					
December 31, 2019	134,564	56,479	11,136	235,551	241,438
Revisions of previous estimates	(49,066)	(3,628)	(8,251)	(12,693)	(63,060)
Improved recovery	—	—	—	—	—
Purchases of minerals in place	7	—	—	8	8
Extensions and discoveries	1,578	962	2,824	11,914	7,349
Production	(16,305)	(3,376)	(825)	(25,802)	(24,806)
Sales of minerals in place	(13)	—	—	(23)	(17)
December 31, 2020	70,766	50,437	4,883	208,956	160,912
Revisions of previous estimates	29,423	980	175	37,387	36,809
Improved recovery	—	—	—	—	—
Purchases of minerals in place	57	—	—	—	57
Extensions and discoveries	39,822	6,022	—	52,832	54,649
Production	(15,797)	(3,316)	(568)	(27,160)	(24,208)
Sales of minerals in place	(26)	(22)	—	(511)	(133)
December 31, 2021	124,245	54,101	4,490	271,504	228,087
Net proved developed reserves					
End of year 2019	63,696	25,085	9,286	116,285	117,447
End of year 2020	36,559	22,894	808	105,045	77,768
End of year 2021	60,668	24,518	592	140,755	109,237
Net proved undeveloped reserves					
End of year 2019	70,869	31,395	1,850	119,266	123,991
End of year 2020	34,207	27,544	4,075	103,910	83,144
End of year 2021	63,578	29,584	3,898	130,749	118,851

Revisions of previous estimates

In 2020, the Company realized total proved revisions of -63,060 mboe. These revisions are primarily due to changes in the constant pricing from YE 2019 (the average first day-of-the-month price for WTI decreased from $55.85/bbl in 2019 to $39.54/bbl in 2020). The Company realized a 65,780 mboe loss in Canada and a 3,901 mboe loss in the US due to pricing changes. The Company also realized positive revisions in both Canada and the US. In Canada positive revisions of 5,139 mboe were realized due to the result of performance versus previous forecasts. In the U.S. positive revisions of 1,482 mboe are also the result of performance versus previous forecasts.

Revisions of previous estimates

In 2021, the Company realized total proved revisions of 36,809 mboe. These revisions consisted of: (i) positive revisions of 29,574 mboe in Canada and 3,182 mboe in the US due to an increase in YE 2021 constant pricing as compared to YE 2020 (WTI moved to $66.55/bbl from $39.54/bbl), (ii) positive revisions of 7,576 mboe in our Heavy oil assets and 344 mboe in our Duvernay assets as a result of improved performance as compared to previous forecasts, (iii) negative revisions of 2,417 mboe in our Viking assets and 609 mboe in our Eagle Ford assets due to lower performance as compared to previous forecasts, and (iv) negative revisions of 841 mboe due to capital plan changes in our Conventional assets.

Extensions and Discoveries

In 2021, the Company added 54,649 mboe of net proved reserves These revisions consisted of positive revisions of 48,026 in Canada and 6,623 in the United States due to drilling activity undertaken in 2021.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Petroleum and Natural Gas Reserves

The following information has been developed utilizing procedures prescribed by ASC 932 and based on crude oil, NGL and natural gas reserves and production volumes estimated by Baytex's independent reserves evaluator, McDaniel & Associates Consultants Ltd. The methodology used in calculating our price assumptions for the standardized measure of discounted future net cash flows for reserves estimation is based upon the average first-day-of-the-month prices during the year.

Future production and development costs are based on forecast price assumptions and assume the continuation of existing economic, operating and regulatory conditions. Future income taxes are calculated by applying statutory income tax rates to future pre-tax cash flows after providing for the tax cost of the petroleum and natural gas properties based upon existing laws and regulations. A 10% discount factor was applied to the future net cash flows.

The information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the fair market value of Baytex's petroleum and natural gas properties. Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated. The prescribed discount rate of 10% may not appropriately reflect interest rates.

The computation of the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves was based on an unweighted arithmetic average of the first-day-of-the-month price for each month in 2021 and 2020.

	Commodity Pricing	
	2021	**2020**
WTI crude (US$/bbl)	$ 66.55	$ 39.54
Edmonton Light crude (Cdn$/bbl)	$ 78.15	$ 45.56
Western Canadian Select crude (WCS) [1] (Cdn$/bbl)	$ 66.43	$ 36.90
AECO spot (Cdn$/mmbtu)	$ 3.57	$ 2.23
Henry Hub (US$/mmbtu)	$ 3.64	$ 2.00
Exchange rate (US$/Cdn$)	0.7980	0.7440

(1) Price used in the preparation of heavy oil and bitumen reserves in Canada.

The standardized measure of discounted future net cash flows relating to net proved petroleum and natural gas reserves are as follows:

	Canada		United States		Total [2]	
(thousands of Canadian dollars)	**2021**	**2020**	**2021**	**2020**	**2021**	**2020**
Future cash inflows	$ 6,585,366	$ 1,664,979	$ 5,864,021	$ 3,743,041	$ 12,449,387	$ 5,408,020
Future production costs	(2,467,626)	(759,574)	(1,597,747)	(1,622,638)	(4,065,373)	(2,382,212)
Future development costs [1]	(1,828,635)	(643,571)	(824,991)	(826,413)	(2,653,627)	(1,469,984)
Future income taxes	(102,932)	—	(477,746)	(18,752)	(580,678)	(18,752)
Future net cash flows [2]	2,186,172	261,834	2,963,538	1,275,238	5,149,710	1,537,072
Deduct: 10% annual discount factor	(632,248)	31,709	(1,315,108)	(566,538)	(1,947,356)	(534,829)
Standardized measure [2]	$ 1,553,924	$ 293,543	$ 1,648,430	$ 708,701	$ 3,202,354	$ 1,002,243

(1) Our estimated future costs to settle asset retirement obligations includes both: (i) estimated costs associated with future undrilled proved locations, and (ii) estimated costs associated with producing reserves. These costs are included in the "Future development costs" line.
(2) The data in the table may not add due to rounding.

Reconciliation of Changes in Standardized Measure of Future Net Cash Flows Discounted at 10% per Year Relating to Net Proved Petroleum and Natural Gas Reserves

As at December 31, 2021 (thousands of Canadian dollars)		Canada	United States	Total [1]
Balance, beginning of year	$	293,543 $	708,701 $	1,002,243
Sales, net of production costs		(663,484)	(436,864)	(1,100,348)
Net change in prices and production costs related to future production		992,488	1,166,873	2,159,360
Changes in previously estimated production costs incurred during the period		(284,411)	(42,131)	(326,542)
Development costs incurred during the period		204,912	105,093	310,005
Extensions, discoveries and improved recovery, net of related costs		497,990	77,229	575,219
Revisions of previous quantity estimates		542,259	183,285	725,544
Sales of reserves in place		(1,553)	(429)	(1,982)
Purchases of reserves in place		90	—	90
Accretion of discount		29,354	71,450	100,804
Net change in income taxes		(57,264)	(184,776)	(242,040)
Balance, end of year [1]	$	1,553,924 $	1,648,430 $	3,202,354

As at December 31, 2020 (thousands of Canadian dollars)		Canada	United States	Total [1]
Balance, beginning of year	$	1,263,346 $	1,286,467 $	2,549,814
Sales, net of production costs		(230,246)	(201,770)	(432,016)
Net change in prices and production costs related to future production		(777,611)	(773,203)	(1,550,814)
Changes in previously estimated production costs incurred during the period		607,008	134,253	741,260
Development costs incurred during the period		170,462	105,388	275,850
Extensions, discoveries and improved recovery, net of related costs		22,234	9,246	31,480
Revisions of previous quantity estimates		(887,803)	(39,120)	(926,923)
Sales of reserves in place		(206)	—	(206)
Purchases of reserves in place		24	—	24
Accretion of discount		126,335	134,536	260,870
Net change in income taxes		—	52,904	52,904
Balance, end of year [1]	$	293,543 $	708,701 $	1,002,243

(1) The data in the table may not add due to rounding.

Capitalized Costs Relating to Petroleum and Natural Gas Producing Activities

As at December 31, 2021 (thousands of Canadian dollars)		Canada	United States	Total
Proved properties	$	6,713,666 $	4,919,851 $	11,633,517
Unproved properties		88,406	84,418	172,824
Total capital costs		6,802,072	5,004,269	11,806,341
Accumulated depletion and impairment		(4,257,833)	(2,911,313)	(7,169,146)
Net capitalized costs	$	2,544,239 $	2,092,956 $	4,637,195

As at December 31, 2020 (thousands of Canadian dollars)		Canada	United States	Total
Proved properties	$	6,580,549 $	4,843,127 $	11,423,676
Unproved properties		99,989	91,876	191,865
Total capital costs		6,680,538	4,935,003	11,615,541
Accumulated depletion and impairment		(5,112,622)	(3,233,506)	(8,346,128)
Net capitalized costs	$	1,567,916 $	1,701,497 $	3,269,413

Baytex Energy Corp.
Supplemental Disclosures about Extractive Activities - Oil and Gas (unaudited)
December 31, 2021

Costs Incurred in Petroleum and Natural Gas Property Acquisition, Exploration and Development Activities

For year ended December 31, 2021 (thousands of Canadian dollars)		Canada	United States	Total
Property acquisition costs				
Proved properties	$	60	$ —	$ 60
Unproved properties		1,497	—	1,497
Development costs [1]		204,912	105,093	310,005
Exploration costs [2]		3,298	—	3,298
Total	$	209,767	$ 105,093	$ 314,860

For year ended December 31, 2020 (thousands of Canadian dollars)		Canada	United States	Total
Property acquisition costs				
Proved properties	$	—	$ —	$ —
Unproved properties		—	—	—
Development costs [1]		170,462	105,388	275,850
Exploration costs [2]		4,490	—	4,490
Total	$	174,952	$ 105,388	$ 280,340

(1) Development and facilities capital expenditures.
(2) Cost of geological and geophysical capital expenditures and drilling costs for exploratory wells.

Results of Operations for Producing Activities

For year ended December 31, 2021 (thousands of Canadian dollars except per boe amounts)		Canada	United States	Total
Petroleum and natural gas revenues, net of royalties	$	1,006,831	$ 522,208	$ 1,529,039
Less:				
Operating costs, production and mineral taxes		257,658	85,344	343,002
Transportation and blending expense		117,950	—	117,950
Exploration and evaluation		15,212	—	15,212
Depletion and impairment		(796,865)	(286,608)	(1,083,473)
Operating loss		1,412,876	723,472	2,136,348
Income tax expense		(548)	1,820	1,272
Results of operations [1]	$	1,413,424	$ 721,652	$ 2,135,076

For year ended December 31, 2020 (thousands of Canadian dollars except per boe amounts)		Canada	United States	Total
Petroleum and natural gas revenues, net of royalties	$	525,677	$ 286,065	$ 811,742
Less:				
Operating costs, production and mineral taxes		247,050	84,295	331,345
Transportation and blending expense		76,818	—	76,818
Exploration and evaluation		14,011	—	14,011
Depletion and impairment		2,046,420	792,659	2,839,079
Operating income (loss)		(1,858,622)	(590,889)	(2,449,511)
Income tax recovery		469	105	574
Results of operations [1]	$	(1,859,091)	$ (590,994)	$ (2,450,085)

(1) Excludes corporate overhead and interest costs.