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, 2023
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)

Baytex Energy USA, Inc.
16285 Park Ten Place, Ste 500
Houston, Texas 77084
(713) 722-6500
(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**
Common Shares	BTE	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

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: 821,680,619

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. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ¨

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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, 2023, 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, 2023, 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, 2023, 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, 2023, 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 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 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 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 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, 2023, filed as Exhibit 99.2 to this Annual Report on Form 40-F, and is incorporated herein by reference. As permitted by the Sarbanes-Oxley Act of 2002 and applicable rules related to business acquisitions, the previous Ranger Oil Corporation ("Ranger") operations have been excluded from the Registrant's annual assessment of internal controls over financial reporting.

The table below presents the summary financial information included in the Corporation’s consolidated annual financial statements for the excluded controls related to the acquired business:

(thousands of Canadian dollars)

Ranger Oil Corporation. Selected financial information from the statement of earnings	June 21 - December 31, 2023
Total gross revenues	**$ 939,448**
Net income (loss)	165,100

(thousands of Canadian dollars)

Ranger Oil Corporation. Selected financial information from the statement of financial position	As at December 31, 2023
Total current assets	**$ 220,279**
Total non-current assets	3,308,962
Total current liabilities	250,808
Total non-current liabilities	97,745

The Registrant is in the process of integrating operations and will be expanding its internal control over financial reporting compliance regime to include the acquired Ranger assets over the next year.

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, 2023, 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, 2023, 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, Ms. Angela Lekatsas and Ms. Tiffany Thom Cepak 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.baytexenergy.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, 2023, 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 described in paragraph 11 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 "Contractual Obligations" in the Registrant's Management's Discussion and Analysis for the year ended December 31, 2023, 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. Jennifer Maki, Ms. Angela Lekatsas, Ms. Tiffany Thom Cepak and Mr. Don Hrap.

Mine Safety Disclosure

Not applicable.

Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

Recovery of Erroneously Awarded Compensation

Not applicable.

Compliance with NYSE Corporate Governance Rules

As a Canadian corporation listed on the NYSE, we are not required to comply with most of the NYSE's corporate governance standards, and instead may comply with Canadian corporate governance practices. However, we are required to disclose the significant differences between our corporate governance practices and the requirements applicable to U.S. domestic companies listed on the NYSE. These significant differences are disclosed on our website at https://www.baytexenergy.com/sustainability-esg/governance/. Except as disclosed on our website, we are in compliance with the NYSE corporate governance standards in all significant respects.

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 February 28, 2024.

BAYTEX ENERGY CORP.

By: */s/ Chad L. Kalmakoff*

Name: Chad L. Kalmakoff

Title: Chief Financial Officer

EXHIBIT INDEX

Exhibit No.	Document
97.1	Executive Incentive Compensation Clawback Policy, dated as of November 24, 2023.
99.1	Annual Information Form of the Registrant for the fiscal year ended December 31, 2023.
99.2	Audited Consolidated Financial Statements of the Registrant for the year ended December 31, 2023 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, 2023.
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 Files.

Exhibit 97.1



EXECUTIVE INCENTIVE COMPENSATION CLAWBACK POLICY
(this "**Policy**")

As Amended and Restated by the Board on November 24, 2023.

1. **Recoupment.** If Baytex Energy Corp. ("**Baytex Energy**" or the "**Company**") is required to prepare a Restatement, the Board shall, unless determined to be Impracticable, take reasonably prompt action to recoup all Recoverable Compensation from any Covered Person. This Policy is in addition to (and not in lieu of) any right of repayment, forfeiture or off-set against any Covered Person that may be available under applicable law or otherwise (whether implemented prior to or after adoption of this Policy). The Board may, in its sole discretion and in the exercise of its business judgment, determine whether and to what extent additional action is appropriate to address the circumstances surrounding any recovery of Recoverable Compensation tied to a Restatement and to impose such other discipline as it deems appropriate. In addition, in the event that any Executive Officer is found to have engaged in intentional misconduct, fraud, theft or embezzlement, the Board may in its discretion, to the full extent permitted by applicable law and to the extent it determines that it is in best interests of Baytex Energy to do so, require the reimbursement of some or all of the after-tax amount of any Incentive Compensation already paid or awarded in the previous 12 months or forfeit any vested or unvested Incentive Compensation awards awarded in the previous 12 months regardless of whether or not a Restatement has occurred or is required.

2. **Method of Recoupment.** Subject to applicable law, the Board may seek to recoup Recoverable Compensation by (i) requiring a Covered Person to repay such amount to the Company; (ii) offsetting a Covered Person's other compensation; or (iii) such other means or combination of means as the Board, in its sole discretion, determines to be appropriate. To the extent that a Covered Person fails to repay all Recoverable Compensation to the Company as determined pursuant to this Policy, the Company shall take all actions reasonable and appropriate to recover such amount, subject to applicable law. The applicable Covered Person shall be required to reimburse the Company for any and all expenses reasonably incurred (including legal fees) by the Company in recovering such amount.

3. **Administration of Policy.** The Board shall have full authority to administer, amend or terminate this Policy. The Board shall, subject to the provisions of this Policy, make such determinations and interpretations and take such actions in connection with this Policy as it deems necessary, appropriate or advisable. All determinations and interpretations made by the Board shall be final, binding and conclusive. Notwithstanding anything in this Section 3 to the contrary, no amendment or termination of this Policy shall be effective if such amendment or termination would (after taking into account any actions taken by the Company contemporaneously with such amendment or termination) cause the Company to violate securities laws applicable to the Company, rules of the Toronto Stock Exchange, rules of the U.S. Securities and Exchange Commission (the "**SEC**") or any other any national securities exchange or national securities association on which the Company's securities are then listed. The Board shall consult with the Company's audit committee

and chief financial officer, as applicable, as needed in order to properly administer and interpret any provision of this Policy.

4. **Acknowledgement by Executive Officers.** The Board may provide notice to and seek written acknowledgement of this Policy from each Executive Officer; provided that the failure to provide such notice or obtain such acknowledgement shall not affect the applicability or enforceability of this Policy. For purposes of clarity, such notice and acknowledgement may be contained within a separate agreement (such as an employment, severance, retention, bonus, incentive compensation, equity award or similar agreement) that may, in whole or in part, be subject to this Policy.

5. **No Indemnification.** Notwithstanding the terms of any of the Company's organizational documents, any corporate policy or any contract, the Company shall not indemnify any Covered Person against the loss of any Recoverable Compensation.

6. **Disclosures and Record Keeping.** The Company shall make all disclosures and filings with respect to this Policy and maintain all documents and records that are required of the Company by the applicable rules and forms of the SEC (including, without limitation, Rule 10D-1 under the Securities Exchange Act of 1934 (the "**Exchange Act**")) and any applicable exchange listing standard.

7. **Governing Law.** The validity, construction, and effect of this Policy and any determinations relating to this Policy shall be construed in accordance with the laws of the Province of Alberta and the federal laws of Canada applicable therein without regard to its conflicts of laws principles.

8. **Successors.** This Policy shall be binding and enforceable against all Covered Persons and their beneficiaries, heirs, executors, administrators or other legal representatives.

9. **Definitions.** In addition to terms otherwise defined in this Policy, the following terms, when used in this Policy, shall have the following meanings:

"Applicable Period" means the three completed fiscal years preceding the earlier of: (i) the date that the Board, or the officer or officers of the Company authorized to take such action if Board action is not required, concludes, or reasonably should have concluded, that the Company is required to prepare a Restatement; or (ii) the date a court, regulator, or other legally authorized body directs the Company to prepare a Restatement. The Applicable Period shall also include any transition period (that results from a change in the Company's fiscal year) of less than nine months within or immediately following the three completed fiscal years. For purposes of this Policy, the Board shall be deemed to have reasonably concluded that a Restatement is required on the date that the Company's Audit Committee or the Company's chief financial officer, as applicable, informs the Board in writing that such a Restatement will be required, unless the Audit Committee informs the Board that an alternative date is more accurate for purposes of determining the Applicable Period.

"Board" means the Board of Directors of Baytex Energy, or, if determined by the Board of Directors of Baytex Energy, one of its committees.

"Covered Person" means any person who receives Recoverable Compensation.

"Executive Officer" includes the Company's current or former president, principal financial officer, principal accounting officer (or if there is no such accounting officer, the controller), any vice-president of the Company in charge of a principal business unit, division, or function (such as sales, administration, or finance), any other officer who performs a policy-making function, or any other person (including any executive officer of the Company's controlled affiliates) who performs similar policy-making functions for the Company, and, in the

sole discretion of the Board, may also include any other current or former employee or consultant of Baytex Energy who is serving, or who served, as a vice-president or more senior officer of Baytex Energy. For purposes of clarity, the term "Executive Officer" shall include, at a minimum, any executive officers of the Company identified pursuant to 17 CFR § 229.401(b).

"Financial Reporting Measure" means a measure that is determined and presented in accordance with the accounting principles used in preparing the Company's financial statements (including "non-GAAP" financial measures, such as those appearing in earnings releases), and any measure that is derived wholly or in part from such measure. Share price and total shareholder return ("**TSR**") are Financial Reporting Measures. Examples of additional Financial Reporting Measures include measures based on: revenues, net income, free cash flow, operating income, financial ratios, EBITDA, liquidity measures, return measures (such as return on capital), earnings measures (such as earnings per share), or any such financial reporting measure relative to a peer group. For the avoidance of doubt, a Financial Reporting Measure need not be presented within the Company's financial statements or included in a filing made by the Company with the SEC.

"Impracticable" means, after exercising a normal due process review of all the relevant facts and circumstances and taking all steps required of the Company by Exchange Act Rule 10D-1 and any applicable exchange listing standard, the Board determines that recovery of the Incentive Compensation is impracticable because: (i) it has determined that the direct expense that the Company would pay to a third party to assist in recovering the Incentive Compensation would exceed the amount to be recovered; (ii) it has concluded that the recovery of the Incentive Compensation would violate home country law adopted prior to November 28, 2022; or (iii) it has determined that the recovery of Incentive Compensation would cause a tax-qualified retirement plan, under which benefits are broadly available to the Company's employees, to fail to meet the requirements of 26 U.S.C. 401(a)(13) or 26 U.S.C. 411(a) and regulations thereunder.

"Incentive Compensation" includes any compensation that is granted, earned, or vested based wholly or in part upon the attainment of a Financial Reporting Measure; however it does not include: (i) base salaries; (ii) discretionary cash bonuses; (iii) awards (either cash or equity) that are based upon subjective, strategic or operational standards; and (iv) equity awards that vest solely on the passage of time. Notwithstanding anything to the contrary in the foregoing, the Board may, in its sole discretion, determine to include in "Incentive Compensation" for purposes of this Policy any other bonus or other incentive compensation or equity-based compensation awarded to an Executive Officer in relation to such Executive Officer's role as an officer of Baytex Energy, which may include, without limitation, cash bonuses paid under any short-term incentive plans, awards under any long-term incentive plans, or any payment (or other compensation) made upon vesting or settlement of any awards under any long-term incentive plan.

"Received" – Incentive Compensation is deemed "Received" in any Company fiscal period during which the Financial Reporting Measure specified in the Incentive Compensation award is attained, even if the payment or grant of the Incentive Compensation occurs after the end of that period.

"Recoverable Compensation" means all Incentive Compensation (calculated on a pre-tax basis) Received on or after October 2, 2023 by a person: (i) after beginning service as an Executive Officer; (ii) who served as an Executive Officer at any time during the performance period for that Incentive Compensation; (iii) while the Company has or had a class of securities listed on a national securities exchange or national securities association; and (iv) during the Applicable Period, that exceeds or exceeded the amount of Incentive Compensation that otherwise would have been Received had the amount been determined based on the Financial Reporting Measures, as reflected in the Restatement. With respect to Incentive Compensation based on share price or TSR, when the amount of erroneously awarded compensation is not subject to mathematical recalculation directly from the information in a Restatement, the amount must be based on a reasonable estimate of the effect of the Restatement on the share price or TSR upon which the Incentive Compensation was Received. Notwithstanding the foregoing, the Board, in its sole discretion, may determine it is appropriate to also include in Recoverable Compensation (a) Incentive Compensation that was awarded to an Executive

Officer after January 1, 2019 and/or (b) the proceeds from the sale of Baytex Energy shares during the first 12 months following the first public issuance or filing with the SEC (whichever occurs first) of the financial statement requiring a Restatement.

"Restatement" means an accounting restatement of any of the Company's financial statements due to the Company's material noncompliance with any financial reporting requirement under U.S. securities laws, including any required accounting restatement to correct an error in previously issued financial statements that is material to the previously issued financial statements (often referred to as a "Big R" restatement), or that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period (often referred to as a "little r" restatement). As of the effective date of this Policy (but subject to changes that may occur in accounting principles and rules following the effective date), a Restatement does not include situations in which financial statement changes did not result from material non-compliance with financial reporting requirements, such as, but not limited to retrospective: (i) application of a change in accounting principles; (ii) revision to reportable segment information due to a change in the structure of the Company's internal organization; (iii) reclassification due to a discontinued operation; (iv) application of a change in reporting entity, such as from a reorganization of entities under common control; (v) adjustment to provision amounts in connection with a prior business combination; and (vi) revision for share splits, share dividends, reverse share splits or other changes in capital structure.

Exhibit 99.1



ANNUAL INFORMATION FORM

2023

February 28, 2024

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APPENDICES:

APPENDIX A REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

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.

CRA means the Canada Revenue Agency.

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.

Ranger means Ranger Oil Corporation.

Ranger Merger means the acquisition of all of the issued and outstanding Class A common stock of Ranger by Baytex by way of merger of Ranger and Ranger Sub.

Ranger Sub means Nebula Merger Sub, LLC, being an indirect wholly owned subsidiary of Baytex.

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, which was terminated and discharged as of June 28, 2022.

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.

2023 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 April 27, 2023.

2024 Notes means the 5.625% senior unsecured notes due June 1, 2024 issued by Baytex pursuant to the 2014 Debt Indenture which were redeemed as of June 2, 2022.

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

2030 Notes means the 8.500% senior unsecured notes due April 30, 2030 issued by Baytex pursuant to the 2023 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 February 28, 2024 for the year ended December 31, 2023.

Baytex Annual 2023 MD&A means Baytex's annual MD&A dated February 28, 2024 for the year ended December 31, 2023.

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 US$1.1 billion secured covenant-based revolving credit facilities with a syndicate of financial institutions.

CSS means cyclic steam stimulation.

GHG means greenhouse gas.

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

NCIB normal course issuer bid.

Preferred Shares means preferred shares of Baytex.

SAGD means steam-assisted gravity drainage.

Senior Notes means, collectively, the 2027 Notes and the 2030 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.

Independent Engineering

Baytex Reserves Report means the report of McDaniel dated February 1, 2024 entitled "Baytex Energy Corp., Evaluation of Petroleum Reserves, Based on Forecast Prices and Costs, As of December 31, 2023".

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, as of a given date, based on:

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

(b) the use of established technology; and

(c) specified economic conditions, which are generally accepted as being reasonable (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:

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

(b) 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 2024 guidance for exploration and development expenditures and production; our five-year outlook including expected production, production growth and annual capital spending; our intentions to continue allocating our annual free cash flow[(1)] to shareholder returns through share buybacks and debt reduction; our dividend policy and our intentions to continue paying dividends on a consistent basis and the timing thereof; our goal of building value by developing our assets and completing selective acquisitions; our belief that our asset base is somewhat unique; our commitment to restoring our 2020 end-of-life well inventory to zero and the anticipated timing thereof; our ability to mitigate and adapt to changes in oil and gas prices; 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 2024; development plans for our properties; the expected benefits and continued performance of our increased Eagle Ford scale as a result of the Merger; undeveloped lease expiries; when we expect to pay material income taxes; our working interest production volume for 2024 based on the future net revenue disclosed in our reserves; our risk management policy's ability to manage our exposure to fluctuations in commodity prices, foreign exchange and interest rates; 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 and our expectations that interest or other funding costs would not make development of any of our properties uneconomic; the impact of existing and proposed governmental and environmental regulation; our assessment of our tax filing position for the years 2011 through 2015; our expectations regarding the timing of receiving a judgement with respect to our notices of appeal with the Tax Court of Canada; and our expectations regarding timing should we be unsuccessful at the Tax of Court of Canada with respect to the aforementioned notices of appeal.

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 crude 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; that we will have sufficient financial resources in the future to provide shareholder returns; 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 risk of an extended period of low oil and natural gas prices; risks associated with our ability to develop our properties and add reserves; that we may not achieve the expected benefits of acquisitions and we may sell assets below their carrying value; the availability and cost of capital or borrowing; restrictions or costs imposed by climate change initiatives and the physical risks of climate change; the impact of an energy transition on demand for petroleum productions; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; changes in income tax or other laws or government incentive programs; risks associated with large projects; risks associated with higher a higher concentration of activity and tighter drilling spacing; costs to develop and operate our properties; current or future controls, legislation or regulations; restrictions on or access to water or other fluids; public

perception and its influence on the regulatory regime; new regulations on hydraulic fracturing; 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; risks associated with a third-party operating our Eagle Ford properties; additional risks associated with our thermal heavy crude oil projects; our ability to compete with other organizations in the oil and gas industry; risks associated with our use of information technology systems; adverse 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 associated with expansion into new activities; the impact of Indigenous claims; risks of counterparty default; impact of geopolitical risk and conflicts; loss of foreign private issuer status; conflicts of interest between the Corporation and its directors and officers; variability of share buybacks and dividends; 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.

The Corporation's future shareholder distributions, including but not limited to the payment of dividends and the future acquisition by the Corporation of Common Shares pursuant to a share buyback (including through its NCIB), if any, and the level thereof is uncertain. Any decision to pay dividends on the Common Shares (including the actual amount, the declaration date, the record date and the payment date in connection therewith) or acquire Common Shares pursuant to a share buyback will be subject to the discretion of the Board and may depend on a variety of factors, including, without limitation, the Corporation's business performance, financial condition, financial requirements, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions (including covenants contained in the agreements governing any indebtedness that the Corporation has incurred or may incur in the future, including the terms of the Credit Facilities) and satisfaction of the solvency tests imposed on the Corporation under applicable corporate law. There can be no assurance of the number of Common Shares that the Corporation will acquire pursuant to a share buyback, if any, in the future. Further, the payment of dividends to shareholders is not assured or guaranteed and dividends may be reduced or suspended entirely.

This AIF contains information that may be considered a financial outlook under applicable securities laws about the Corporation's potential financial position, including, but not limited to, our 2024 guidance for development expenditures; our five-year outlook including our expected annual capital spending; our intentions of continuing to allocate our annual free cash flow[(1)] to shareholder returns through a share buyback and debt reduction; our intentions to continue paying dividends; and when we expect to pay material income taxes, all of which are subject to numerous assumptions, risk factors, limitations and qualifications, including those set forth in the above paragraphs. The actual results of operations of the Corporation and the resulting financial results will vary from the amounts set forth in this AIF and such variations may be material. This information has been provided for illustration only and with respect to

future periods are based on budgets and forecasts that are speculative and are subject to a variety of contingencies and may not be appropriate for other purposes. Accordingly, these estimates are not to be relied upon as indicative of future results. Except as required by applicable securities laws, the Corporation undertakes no obligation to update such financial outlook, whether as a result of new information, future events or otherwise. The financial outlook contained in this AIF was made as of the date of this AIF and was provided for the purpose of providing further information about the Corporation's potential future business operations. Readers are cautioned that the financial outlook contained in this AIF is not conclusive and is subject to change.

(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. See "Specified Financial Measures" in the Baytex Annual 2023 MD&A for information related to this measure, which section has been incorporated by reference herein. The Baytex Annual 2023 MD&A are available on SEDAR+ at www.sedarplus.com.

New York Stock Exchange

As a Canadian corporation listed on the NYSE, we are not required to comply with most of the NYSE's corporate governance standards and, instead, may comply with Canadian corporate governance practices. We are, however, required to disclose the significant differences between our corporate governance practices and the requirements applicable to U.S. domestic companies listed on the NYSE. Except as summarized on our website at www.baytexenergy.com, we are in compliance with the NYSE corporate governance standards.

Foreign Private Issuer Status

The Corporation continues to qualify as a foreign private issuer for the purposes of its U.S. securities filings based on the most recent assessment performed as at June 30, 2023. The Corporation is required to reassess this conclusion annually, at the end of the second quarter. See "*Risk Factors – The Corporation could lose its status as a "foreign private issuer* " in the United States, which may result in additional compliance costs and restricted access to capital markets.

Access to Documents

Any document referred to in this AIF and described as being accessible on the SEDAR+ website at *www.sedarplus.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. The Common Shares are currently traded on the TSX and the NYSE under the symbol "BTE".

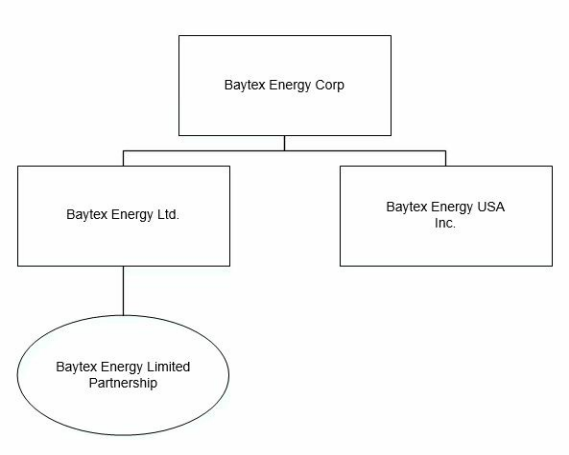
Inter-Corporate Relationships

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 or 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

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 OPEC+ 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, which was comprised of 15,710 bbl/d of light and medium crude oil, 20,449 bbl/d of heavy crude oil, 1,739 bbl/d of bitumen, 15,291 bbl/d of tight oil, 12,032 bbl/d of NGL, 40,051 mcf/d of shale gas and 49,555 mcf/d of conventional natural gas, 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 2024 Notes.

On December 1, 2021 we announced our anticipated 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.

2022

Commodity prices were strong throughout the year, they increased during the first half of the year due to uncertainty surrounding global energy security and then retreated as a result of concerns over high inflation and slowing economic activity. The price for WTI averaged US$94.23/bbl for the year.

In February 2022, as a result of Baytex's significantly improved financial position, we announced an intent to allocate approximately 25% of annual free cash flow[2] to direct shareholder returns through a share buyback with the remainder of free cash flow continuing to be allocated to debt reduction.

On April 1, 2022 we amended our Credit Facilities to, among other things, extend the term by two years to April 2026 and increase the aggregate principal amount available thereunder to US$850 million.

On May 2, 2022 we announced the approval of an NCIB allowing us to purchase up to 56,300,143 Common Shares during the 12-month period commencing May 9, 2022 and ending May 8, 2023. During the year ended December 31, 2022 we repurchased 24.3 million Common Shares at an average price of $6.54 per Common Share. In connection with the NCIB, we entered into entered into an automatic share purchase plan with RBC Dominion Securities Inc. ("RBC") allowing RBC to purchase Common Shares under the NCIB when the Corporation would ordinarily not be permitted to purchase Common Shares due to regulatory restrictions and customary self-imposed blackout periods.

On June 1, 2022 we redeemed and canceled our remaining US$200 million of 2024 Notes. During the year we also made open market repurchases of US$90 million of 2027 Notes.

Effective November 4, 2022 the Board of Directors appointed Mr. Eric Greager to the position of President and Chief Executive Officer and as a Director, replacing Mr. LaFehr. Mr. LaFehr concurrently resigned as a Director, but remained as an advisor to the Board and to the President and Chief Executive Officer until February of 2023.

On November 17, 2022 we announced that Mr. Chad Kalmakoff was promoted to Chief Financial Officer of the Corporation from his previous position of Vice President, Finance, replacing Mr. Rodney Gray. Mr. Rodney Gray concurrently resigned as Executive Vice President and Chief Financial Officer.

On December 7, 2022 we announced our anticipated 2023 exploration and development expenditures range of $575-650 million designed to generate average annual production of 86,000-89,000 boe/d. We also announced that once the Corporation's net debt[1] decreased to $800 million we would increase direct shareholder returns to 50% of free cash flow[2] and an ultimate debt target.

2023

Oil prices were lower in 2023 as a result of global supply growth which resulted in a more balanced crude market relative to 2022 when prices were elevated as the global supply shortfall was exacerbated by uncertainty related to Russian supply. The price for WTI averaged US$77.62/bbl for the year.

On February 8, 2023 the Board of Directors appointed Ms. Angela S. Lekatsas as a Director and announced that Mr. Gregory Melchin did not intend to stand for election at the next annual meeting of shareholders.

On February 23, 2023 the Common Shares commenced trading on the NYSE.

On February 28, 2023 Baytex announced its intention to acquire Ranger by way of the Merger. The Merger was completed on June 20, 2023 pursuant to the agreement and plan of merger dated February 27, 2023, as amended from time to time, between Baytex, Ranger and Ranger Sub. As consideration under the Merger, Baytex issued approximately 311.4 million Common Shares and paid $732.8 million in cash to the former security holders of Ranger. Additionally, Baytex assumed CAD $1.1 billion of Ranger's net debt[(1)]. The cash portion of the Merger was funded with the Corporation's expanded US$1.1 billion revolving Credit Facility, a US$150 million two-year term loan facility and the net proceeds from the issuance of US$800 million 2030 Notes. The term loan facility was fully repaid and cancelled in August of 2023.

The Merger increased our Eagle Ford scale and provided an operating platform to effectively allocate capital across the Western Canadian Sedimentary Basin and the Eagle Ford. Production from the Ranger assets is approximately 80% weighted towards high netback light oil and liquids.

In conjunction with closing of the Merger, we increased direct shareholder returns to 50% of free cash flow [(2)], which allowed us to increase the value of our share buyback program and introduce a dividend. The remainder of our free cash flow[(2)] was allocated to debt reduction. On June 23, 2023 we announced the renewal of our NCIB allowing us to purchase up to 68,417,028 Common Shares during the 12-month period commencing June 29, 2023 and ending June 28, 2024. In 2023, we returned approximately $260 million to shareholders through our share buyback program and dividends. As at December 31, 2023, we had repurchased 40.5 million Common Shares under the NCIB for approximately $222 million, representing 4.7% of our issued and outstanding Common Shares, at an average price of $5.48 per Common Share. In addition, during 2023, we declared two quarterly dividends of $0.0225 per Common Share, totaling approximately $38 million.

On closing of the Merger, Jeffrey E. Wojahn and Tiffany ("T.J.") Thom Cepak were appointed to the Board of Directors, providing continuity and experience with the Ranger business and expertise in U.S. regulatory and operating matters.

On November 27, 2023, we announced that we had entered into a definitive agreement to sell certain of our Viking assets located at Forgan and Plato in southwest Saskatchewan (the "**Sold Viking Assets**"), effective October 1, 2023. On December 11, 2023, we completed the divestiture of the Sold Viking Assets for proceeds of $159.7 million, including closing adjustments. Proceeds from the sale were applied against our Credit Facilities. Production from the Sold Viking Assets at the time of the sale was approximately 4,000 boe/d (100% light and medium crude oil).

(1) Capital management measure. See "Specified Financial Measures" in the Baytex Annual 2023 MD&A for information related to this measure, which section has been incorporated by reference herein. The Baytex Annual 2023 MD&A is available on SEDAR+ at www.sedarplus.com.

(2) Specified financial measure that does not have any standardized meaning prescribed by International Financial Reporting Standards ("**IFRS**") and may not be comparable with the calculation of similar measures presented by other entities. See "*Specified Financial Measures*" in the Baytex Annual 2023 MD&A for information related to this measure, which section has been incorporated by reference herein. The Baytex Annual 2023 MD&A is available on SEDAR+ at www.sedarplus.com.

On December 6, 2023 we announced our anticipated 2024 exploration and development expenditures range of $1.2 to $1.3 billion, which is designed to generate average annual production of 150,000-156,000 boe/d.

Significant Acquisitions

The only significant acquisition completed by the Corporation in the year ended December 31, 2023 was the Merger. See " *Development of our Business – Developments in the Past Three Years – 2023*" above for a summary of the Merger. On June 27, 2023, the Corporation filed a Form 51-102F4 – *Business Acquisition Report* in respect of the Merger, which is available on SEDAR+ at www.sedarplus.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 85% of our production is weighted toward crude oil and NGLs. The Corporation and its predecessors have been in business for more than 30 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 and divestitures.

Competitive Conditions

Baytex is in the oil and natural gas industry, which is highly competitive and capital intensive, and many competitors have financial resources which exceed our own. Baytex competes with other companies for all of its business inputs, including development prospects, access to commodity markets, acquisition opportunities, available capital and staffing. Our asset base is somewhat unique in that we have significant oil and gas assets in both Canada and the United States; however, on the whole, our competitive position is 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 mandate for the reserves and sustainability committee of the 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."

We have published a Corporate Responsibility Report since 2012 and published our seventh report in July of 2023. 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. Our most recent report which outlined our achievements in 2022 included the following highlights:

- Reduced our corporate GHG emissions intensity by 59% from our 2018 baseline, achieving 90% of our goal of reducing our GHG emissions intensity 65% by 2025.
- Completed 379 well abandonments in 2022, the most in our history as we work towards restoring our 2020 end-of-life well inventory of 4,500 wells to zero by 2040.

- Met our Board gender diversity target by having women make up 30% of our Board prior to our 2023 Annual General Meeting.

At the same time, we also released our second Task Force on Climate-Related Financial Disclosures report.

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 2024 by the renegotiation or termination of any contracts to which we are a party.

Personnel

As at December 31, 2023, Baytex had 158 employees in our Calgary office, 70 employees in our Houston office, 65 employees in our Canadian field operations and 74 employees in our US 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, 2023. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2023 and production information represents average working interest production for the year ended December 31, 2023. All of our properties are located onshore.

Eagle Ford - Texas

Our Eagle Ford assets are located in the Eagle Ford shale of South Texas and are comprised of operated assets and non-operated assets. Our operated assets were acquired through the Ranger Merger and are comprised of operated working interests in approximately 190,939 (166,192 net) acres located principally in the Gonzales, Lavaca, Fayette and Dewitt counties with an average working interest of approximately 88%. Our non-operated assets include working interests in approximately 78,212 (19,931 net) acres, comprised of four areas of mutual interest principally located in Karnes County (Sugarloaf, Longhorn, Ipanema and Excelsior) with an average working interest of approximately 25%. Our non-operated position is operated by an operating subsidiary of Marathon Oil Corporation (NYSE: MRO), pursuant to the terms of industry-standard joint operating agreements, joint venture agreements with non-AMI working interest holders where wells produce from AMI and non-AMI lands as well as negotiated agreements with Marathon and other working interest owners related to facilities, marketing and supplemental development. Production from our Eagle Ford assets occurs from the hydraulic fracturing of horizontal wells.

During 2023, production from the Eagle Ford assets averaged approximately 60,997 boe/d, comprised of 49,905 bbl/d of light and medium crude oil (including condensate and NGL) and 66,556 Mcf/d of shale gas. During this period, Baytex participated in the completion of 83 (42.3 net) wells, resulting in 58 (25.8 net) oil wells and 25 (16.5 net) natural gas wells. As at December 31, 2023, our proved plus probable reserves were 418 million boe (292 million proved; 126 million probable).

As at December 31, 2023, the undeveloped land base associated with the Eagle Ford assets consisted of 35,172 net acres

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. Production in the area occurs through primary and polymer flooding recovery methods. During 2023, production from the area averaged approximately 25,537 boe/d, comprised of 23,608 bbl/d of heavy crude oil, 53 bbl/d of NGL and 11,258 Mcf/d of conventional natural gas. In 2023, Baytex drilled 36 (36.0 net) horizontal multi-lateral wells in this area. As at December 31, 2023, we had proved plus probable reserves of 54 million boe (33 million proved; 22 million probable).

Baytex held approximately 284,980 net undeveloped acres in this area as at December 31, 2023.

Lloydminster - Alberta and Saskatchewan

Our Lloydminster assets consist of several geographically dispersed heavy crude oil operations that include primary and thermal production. In some cases, Baytex's heavy crude oil reservoirs are water flooded and polymer flooded. In 2023, production averaged approximately 12,091 boe/d, which was comprised of 10,105 bbl/d of heavy crude oil, 1,747 bbl/d of bitumen, 22 bbl/d of light and medium crude oil, and 1,298 Mcf/d of conventional natural gas. In 2023, Baytex drilled 34 (32.2 net) oil wells in this area. As at December 31, 2023, we had proved plus probable reserves of 84 million boe (25 million proved; 59 million probable).

We held approximately 179,016 net undeveloped acres in this area at December 31, 2023.

Duvernay - Alberta

Baytex holds a large 100% working interest land position in the East Duvernay resource play in central Alberta. Production in the area occurs from the hydraulic fracturing of horizontal wells. In 2023, production averaged 3,719 boe/d, comprised of 3,079 bbl/d of light crude oil and NGL and 3,840 Mcf/d of conventional natural gas. During 2023, Baytex drilled 6 (6.0 net) oil wells. As at December 31, 2023, we

had proved plus probable reserves of 49 million boe (23 million proved; 26 million probable) and net undeveloped lands of approximately 91,844 net acres.

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 Exploration Inc. 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 2023, the Viking assets produced 15,295 boe/d, comprised of 13,323 bbl/d of light and medium crude oil and NGL and 11,834 Mcf/d of conventional natural gas. These assets are characterized by shallow wells with short cycle times and a manufacturing approach to development. In 2023, Baytex completed 148 (140.8 net) oil wells. As at December 31, 2023 we had proved plus probable reserves of 46 million boe (29 million proved; 17 million probable). On December 11, 2023, we completed the divestiture of the Sold Viking Assets located at Forgan and Plato in Southwest Saskatchewan for proceeds of $159.7 million, including closing adjustments. Production from the Sold Viking Assets at the time of the sale was approximately 4,000 boe/d (100% light and medium crude oil), represented approximately 25% of our Viking production at the time of sale. The Sold Viking Assets were geographically separated from our core position.

The undeveloped land base associated with the retained Viking assets consisted of 77,732 net acres at December 31, 2023.

Average Production

The following table indicates our average daily production from our principal properties for the year ended December 31, 2023.

	Heavy Crude Oil (bbl/d)	Bitumen (bbl/d)	Light and Medium Crude Oil (bbl/d)	Tight Oil (bbl/d)	NGL[1] (bbl/d)	Shale Gas (Mcf/d)	Conventional Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada - Heavy								
Peace River	23,608	—	—	—	53	—	11,258	25,537
Lloydminster	10,105	1,747	22	—	—	—	1,298	12,091
Total	33,713	1,747	22	—	53	—	12,556	37,628
Canada - Light								
Viking	—	—	13,078	—	245	—	11,834	15,295
Duvernay	—	—	—	1,881	1,198	3,840	—	3,719
Remaining properties	—	—	594	—	715	—	19,224	4,514
Total	—	—	13,672	1,881	2,158	3,840	31,058	23,528
United States								
Eagle Ford	—	—	—	35,908	13,997	66,556	—	60,997
Grand Total	**33,713**	**1,747**	**13,694**	**37,789**	**16,208**	**70,396**	**43,614**	**122,153**

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, 2023.

($000s)	Canada	United States	Total
Property acquisition costs			
Proved properties	1,556	18,891	20,447
Unproved properties	18,467	—	18,467
Property disposition	(160,256)	—	(160,256)
Total Property acquisition costs, net	(140,233)	18,891	(121,342)
Development Costs [1]	463,198	549,589	1,012,787
Exploration Costs [2]	—	—	—
Total	322,965	568,480	891,445

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, 2023.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	999	871.2	1,160	685.0	124	71.1	241	163.5
BC	—	—	—	—	—	—	—	—
Saskatchewan	2,577	2,311.4	1,520	1,481.5	75	38.3	190	174.4
Texas	1,576	893.0	6	4.0	421	162.0	3	2.0
Total	5,152	4,075.6	2,686	2,170.5	620	271.4	434	339.9

Properties with No Attributed Reserves

The following table sets forth our undeveloped land holdings as at December 31, 2023.

	Undeveloped Acres	
	Gross	Net
Alberta	677,091	548,508
Saskatchewan	231,220	178,673
Texas	60,212	35,172
Total	968,523	762,353

Undeveloped land holdings are lands that have not been assigned reserves as at December 31, 2023. 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, 2023 to be approximately $248 million, as compared to $166 million as at December 31, 2022. This estimate includes undeveloped land holdings added during 2023 from the Ranger Merger. This internal evaluation generally represents

the estimated replacement cost of our undeveloped land and excludes approximately 47,558 net acres of our undeveloped land that we expect to expire on or before December 31, 2024. 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

When forecasted using the commodity price forecasts and inflation rates as of January 1, 2024 used to prepare the Reserves Report Baytex does not expect to pay material cash income taxes prior to 2026 in the U.S. and 2027 in Canada.

Despite this tax horizon, Baytex is subject to other taxes, such as taxes related to the repatriation of foreign earnings, certain U.S. state taxes, global minimum taxes, capital taxes and taxes on share buy backs (together, the "Other Taxes").

Other Taxes amounted to $14 million in 2023 or 1% of EBITDA [(1)]. Baytex forecasts that Other Taxes will average 2% of EBITDA during 2024 and 2025 and that income and Other Taxes combined will increase as a percentage of EBITDA from 2026 onwards, averaging 10 - 15% once available non-capital loss pools are fully utilized, and the full tax horizon is reached.

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, 2023.

	Exploratory Wells		Development Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
CANADA						
Oil Wells	—	—	225	217.2	225	217.2
Natural Gas Wells	—	—	—	—	—	—
Stratigraphic Test Wells	—	—	—	—	—	—
Service Wells	—	—	—	—	—	—
Dry Holes	—	—			—	—
Total	—	—	225	217.2	225	217.2
UNITED STATES						
Oil Wells	—	—	60	23.0	60	23.0
Natural Gas Wells	—	—	18	13.1	18	13.1
Stratigraphic Test Wells	—	—	—	—	—	—
Service Wells	—	—	—	—	—	—
Dry Holes	—	—	—	—	—	—
Total	—	—	78	36.1	78	36.1

(1) Calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.com.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ending December 31, 2024, 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 Crude Oil (bbl/d)	Bitumen (bbl/d)	Light and Medium Crude 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	27,541	2,155	10,079	2,602	2,536	5,967	35,476	51,820
Total Proved plus Probable	32,123	2,580	10,940	2,773	2,744	6,467	38,326	58,626
UNITED STATES								
Total Proved	—	—	—	46,994	22,092	100,069	—	85,765
Total Proved plus Probable	—	—	—	48,485	22,821	103,081	—	88,486
TOTAL								
Total Proved	27,541	2,155	10,079	49,596	24,629	106,036	35,476	137,585
Total Proved plus Probable	32,123	2,580	10,940	51,258	25,565	109,549	38,326	147,112

Note:

(1) Includes condensate.

The Eagle Ford property is the only property that accounts for 20% or more of the estimated 2024 production volumes. Estimated 2024 production volumes for the Eagle Ford property is 85,765 boe/d on a total proved basis and 88,486 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, 2023	Sep. 30, 2023	Jun. 30, 2023	Mar. 31, 2023	Dec. 31, 2023
Average Sales Volume [1]					
CANADA					
Light and Medium Crude Oil (bbl/d)	11,208	14,563	13,831	15,213	13,695
Heavy Crude Oil (bbl/d)	37,336	34,030	31,204	32,222	33,713
Bitumen (bbl/d)	2,233	1,175	1,617	1,969	1,747
Tight Oil (bbl/d)	2,803	2,960	672	1,060	1,881
NGL (bbl/d) [2]	3,069	2,219	1,542	2,000	2,210
Total liquids (bbl/d)	56,649	54,947	48,866	52,464	53,246
Shale Gas (Mcf/d)	6,748	3,996	1,946	2,623	3,840
Conventional Natural Gas (Mcf/d)	41,825	46,061	40,097	46,497	43,614
Total (boe/d)	64,744	63,289	55,874	60,651	61,157
UNITED STATES					
Tight Oil (bbl/d)	54,430	56,458	18,686	13,381	35,908
NGL (bbl/d) [2]	21,774	17,567	9,210	7,237	13,997
Total liquids (bbl/d)	76,204	74,025	27,896	20,618	49,905
Shale Gas (Mcf/d)	116,548	79,722	35,946	32,946	66,556
Total (boe/d)	95,629	87,311	33,887	26,109	60,997
TOTAL					
Light and Medium Crude Oil (bbl/d)	11,208	14,563	13,831	15,213	13,695
Heavy Crude Oil (bbl/d)	37,336	34,030	31,204	32,222	33,713
Bitumen (bbl/d)	2,233	1,175	1,617	1,969	1,747
Tight Oil (bbl/d)	57,233	59,418	19,358	14,441	37,789
NGL (bbl/d) [2]	24,843	19,786	10,752	9,237	16,207
Total liquids (bbl/d)	132,853	128,972	76,762	73,082	103,151
Shale Gas (Mcf/d)	123,296	83,718	37,892	35,569	70,396
Conventional Natural Gas (Mcf/d)	41,825	46,061	40,097	46,497	43,614
Total (boe/d)	160,373	150,600	89,761	86,760	122,154

	Three Months Ended				Year Ended
	Dec. 31, 2023	Sep. 30, 2023	Jun. 30, 2023	Mar. 31, 2023	Dec. 31, 2023
CANADA					
Average Prices Received [3]					
Light and Medium Crude Oil ($/bbl)	99.72	106.32	93.82	99.22	99.87
Heavy Crude Oil ($/bbl)	62.17	84.39	66.26	51.02	66.14
Bitumen ($/bbl)	67.74	85.47	70.02	53.29	67.26
Tight Oil ($/bbl)	100.99	110.10	97.65	99.39	104.08
NGL ($/bbl) [2]	30.26	34.22	33.31	39.90	33.94
Shale Gas ($/Mcf)	2.27	2.57	2.32	3.45	2.55
Conventional Natural Gas ($/Mcf)	2.42	2.73	2.66	3.63	2.88
Total ($/boe) [8]	63.06	79.93	66.34	59.71	67.39
Royalties Paid					
Light and Medium Crude Oil and NGL ($/bbl) [2][4]	7.98	9.49	9.46	9.25	9.08
Heavy Crude Oil ($/bbl)	12.08	14.17	11.05	8.63	11.56
Bitumen ($/bbl)	9.22	9.49	6.83	6.54	7.97
Tight Oil ($/bbl)	11.47	11.56	9.38	13.93	11.66
Shale Gas ($/Mcf)	0.08	0.02	1.66	0.34	0.30
Conventional Natural Gas ($/Mcf)	0.23	0.24	0.23	0.46	0.29
Total ($/boe) [9]	9.69	11.03	9.30	8.03	9.55
Operating Expenses [5]					
Light and Medium Crude Oil and NGL ($/bbl) [2][4]	17.70	16.45	19.57	17.54	17.78
Heavy Crude Oil ($/bbl)	14.86	15.50	16.74	16.36	15.81
Bitumen ($/bbl)	18.27	30.78	26.32	20.52	22.87
Tight Oil ($/bbl)	8.82	10.88	17.67	12.74	11.05
Shale Gas ($/Mcf)	1.47	1.81	2.95	2.12	1.84
Conventional Natural Gas ($/Mcf)	3.07	2.87	3.01	2.68	2.89
Total ($/boe) [9]	15.61	15.98	17.97	16.70	16.51
Transportation Expenses					
Light and Medium Crude Oil and NGL ($/bbl) [2][4]	0.56	0.49	0.53	0.92	0.63
Heavy Crude Oil ($/bbl)	4.52	4.44	4.01	4.69	4.42
Bitumen ($/bbl)	2.09	1.32	1.68	3.79	2.34
Tight Oil ($/bbl)	1.15	0.90	0.64	0.29	0.88
Shale Gas ($/Mcf)	0.19	0.15	0.11	0.05	0.15
Conventional Natural Gas ($/Mcf)	0.23	0.23	0.22	0.30	0.25
Total ($/boe) [9]	3.02	2.76	2.60	3.12	2.88
Resulting Netback [3][6]					
Light and Medium Crude Oil and NGL ($/bbl) [2][4]	58.55	70.36	58.19	64.62	63.22
Heavy Crude Oil ($/bbl)	30.71	50.28	34.46	21.34	34.35
Bitumen ($/bbl)	38.16	43.88	35.19	22.44	34.08
Tight Oil ($/bbl)	79.55	86.76	69.96	72.43	80.49
Shale Gas ($/Mcf)	0.53	0.59	(2.40)	0.94	0.26
Conventional Natural Gas ($/Mcf)	(1.11)	(0.61)	(0.80)	0.19	(0.55)
Total ($/boe) [8]	34.74	50.16	36.47	31.86	38.45

	Three Months Ended				Year Ended
	Dec. 31, 2023	Sep. 30, 2023	Jun. 30, 2023	Mar. 31, 2023	Dec. 31, 2023
UNITED STATES					
Average Prices Received [3]					
Tight Oil ($/bbl)	105.82	108.99	97.47	103.07	105.74
NGL ($/bbl) [2]	32.35	36.03	41.16	51.67	37.42
Shale Gas ($/Mcf)	3.07	3.20	2.52	4.02	3.15
Total ($/boe) [8]	71.34	80.64	67.60	72.22	74.27
Royalties Paid					
Tight Oil ($/bbl)	29.35	29.92	28.61	30.95	29.63
NGL ($/bbl) [2]	8.03	9.18	11.85	13.77	9.75
Shale Gas ($/Mcf)	0.72	0.76	0.62	1.07	0.76
Total ($/boe) [9]	19.42	21.89	19.66	21.02	20.51
Operating Expenses [5][7]					
Tight Oil ($/bbl)	8.17	10.09	9.11	9.03	9.08
NGL ($/bbl) [2]	8.17	10.09	9.11	9.03	9.08
Shale Gas ($/Mcf)	1.36	1.68	1.52	1.51	1.51
Total ($/boe) [9]	8.17	10.09	9.11	9.03	9.08
Transportation Expenses					
Tight Oil ($/bbl)	0.53	0.46	0.21	—	0.44
NGL ($/bbl) [2]	3.34	4.76	0.88	—	2.88
Shale Gas ($/Mcf)	0.22	0.25	0.07	—	0.19
Total ($/boe) [9]	1.33	1.48	0.43	—	1.12
Resulting Netback [3][6]					
Tight Oil ($/bbl)	67.77	68.52	59.54	63.09	66.59
NGL ($/bbl) [2]	12.81	12.00	19.32	28.87	15.71
Shale Gas ($/Mcf)	0.77	0.51	0.31	1.44	0.69
Total ($/boe)	42.42	47.18	38.40	42.17	43.56

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 crude 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, Conventional natural gas and NGL production.

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

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

(8) Non-GAAP measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. See "Specified Financial Measures" in the Baytex Annual 2023 MD&A for information related to this measure, which section has been incorporated by reference herein. The Baytex Annual 2023 MD&A are available on SEDAR+ at www.sedarplus.com.

(9) Supplementary financial measure. See "Royalties", "Operating Expense", and "Transportation Expense" in the Baytex Annual 2023 MD&A for information related to this measure, which section has been incorporated by reference herein. Baytex Annual 2023 MD&A are available on SEDAR+ at www.sedarplus.com.

Marketing Arrangements and Forward Contracts

We market our operated oil and natural gas production with the objective of maximizing value and counterparty performance. We have a portfolio of sales contracts with a variety of pricing mechanisms, term commitments and customers and we also have several committed transportation and processing contracts with volume and term commitments that enable us to transport our production to sales points. Production from our non-operated assets in the Eagle Ford 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 28, 2024, see Note 18 to our audited consolidated financial statements for the year ended December 31, 2023. 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, 2023. The effective date of the Baytex Reserves Report is December 31, 2023 and the preparation date of the statement is February 1, 2024. 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, 2024.

Disclosure of Reserves Data

The following tables are a combined summary as at December 31, 2023 of our proved and probable heavy crude 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*", "Selected Terms - *Reserves and Reserve Categories*" and "Selected Terms - *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, 2023
FORECAST PRICES AND COSTS

CANADA

RESERVES CATEGORY	TIGHT OIL		LIGHT AND MEDIUM CRUDE OIL		HEAVY CRUDE OIL	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)
PROVED:						
Developed Producing	2,613	2,230	9,690	9,128	31,218	26,283
Developed Non-Producing	—	—	414	383	1,416	1,260
Undeveloped	7,226	6,310	15,699	14,882	18,445	16,292
TOTAL PROVED	9,838	8,540	25,803	24,392	51,078	43,834
PROBABLE	11,197	9,144	14,997	13,910	32,935	27,331
TOTAL PROVED PLUS PROBABLE	21,035	17,685	40,799	38,302	84,013	71,165

CANADA

RESERVES CATEGORY	BITUMEN		SHALE GAS		CONVENTIONAL NATURAL GAS [1]	
	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)
PROVED:						
Developed Producing	1,679	1,564	7,822	7,114	52,758	47,825
Developed Non-Producing	—	—	—	—	1,205	1,076
Undeveloped	2,105	1,916	20,135	18,267	23,948	20,760
TOTAL PROVED	3,783	3,480	27,957	25,381	77,910	69,661
PROBABLE	45,754	36,517	32,887	28,883	38,246	33,578
TOTAL PROVED PLUS PROBABLE	49,537	39,997	60,844	54,264	116,156	103,238

CANADA

RESERVES CATEGORY	NATURAL GAS LIQUIDS [2]		TOTAL RESERVES	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
PROVED:				
Developed Producing	3,535	3,025	58,830	51,386
Developed Non-Producing	45	35	2,076	1,856
Undeveloped	6,524	5,768	57,345	51,672
TOTAL PROVED	10,105	8,828	118,252	104,914
PROBABLE	10,452	8,849	127,189	106,161
TOTAL PROVED PLUS PROBABLE	20,557	17,677	245,441	211,075

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	67,960	51,714	137,735	104,187	34,859	26,155
Developed Non-Producing	3,703	2,789	6,761	5,087	1,769	1,327
Undeveloped	81,281	61,843	181,471	135,972	48,107	35,862
TOTAL PROVED	152,944	116,346	325,967	245,246	84,735	63,344
PROBABLE	74,041	56,404	118,877	89,396	31,882	23,839
TOTAL PROVED PLUS PROBABLE	226,985	172,749	444,844	334,642	116,617	87,183

UNITED STATES

RESERVES CATEGORY	TOTAL RESERVES Gross (Mboe)	TOTAL RESERVES Net (Mboe)
PROVED:		
Developed Producing	125,775	95,233
Developed Non-Producing	6,599	4,963
Undeveloped	159,632	120,368
TOTAL PROVED	292,007	220,564
PROBABLE	125,736	95,142
TOTAL PROVED PLUS PROBABLE	417,743	315,706

TOTAL

RESERVES CATEGORY	TIGHT OIL Gross (Mbbl)	TIGHT OIL Net (Mbbl)	LIGHT AND MEDIUM CRUDE OIL Gross (Mbbl)	LIGHT AND MEDIUM CRUDE OIL Net (Mbbl)	HEAVY CRUDE OIL Gross (Mbbl)	HEAVY CRUDE OIL Net (Mbbl)
PROVED:						
Developed Producing	70,573	53,944	9,690	9,128	31,218	26,283
Developed Non-Producing	3,703	2,789	414	383	1,416	1,260
Undeveloped	88,506	68,154	15,699	14,882	18,445	16,292
TOTAL PROVED	162,782	124,886	25,803	24,392	51,078	43,834
PROBABLE	85,238	65,548	14,997	13,910	32,935	27,331
TOTAL PROVED PLUS PROBABLE	248,020	190,434	40,799	38,302	84,013	71,165

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	1,679	1,564	145,556	111,300	52,758	47,825
Developed Non-Producing	—	—	6,761	5,087	1,205	1,076
Undeveloped	2,105	1,916	201,607	154,239	23,948	20,760
TOTAL PROVED	3,783	3,480	353,924	270,627	77,910	69,661
PROBABLE	45,754	36,517	151,764	118,279	38,246	33,578
TOTAL PROVED PLUS PROBABLE	49,537	39,997	505,688	388,906	116,156	103,238

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	38,394	29,180	184,606	146,619
Developed Non-Producing	1,814	1,361	8,675	6,819
Undeveloped	54,631	41,630	216,978	172,039
TOTAL PROVED	94,840	72,172	410,259	325,478
PROBABLE	42,334	32,687	252,925	201,303
TOTAL PROVED PLUS PROBABLE	137,173	104,859	663,184	526,781

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, 2023
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	501,765	754,762	798,250	784,960	755,505	15.53
Developed Non-Producing	57,372	47,709	40,777	35,607	31,623	21.97
Undeveloped	1,216,278	857,704	620,631	457,472	341,292	12.01
TOTAL PROVED	1,775,415	1,660,175	1,459,658	1,278,039	1,128,419	13.91
PROBABLE	3,782,900	2,189,078	1,429,040	1,011,854	758,451	13.46
TOTAL PROVED PLUS PROBABLE	5,558,315	3,849,253	2,888,697	2,289,892	1,886,871	13.69

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	3,941,535	3,236,204	2,708,562	2,348,256	2,090,157	28.44
Developed Non-Producing	233,766	175,727	144,837	125,113	111,115	29.18
Undeveloped	2,078,319	1,179,693	643,633	303,700	78,978	5.35
TOTAL PROVED	6,253,619	4,591,624	3,497,032	2,777,068	2,280,250	15.85
PROBABLE	3,989,677	2,256,259	1,414,413	958,969	691,108	14.87
TOTAL PROVED PLUS PROBABLE	10,243,296	6,847,882	4,911,445	3,736,037	2,971,358	15.56

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	4,443,301	3,990,966	3,506,812	3,133,215	2,845,662	23.92
Developed Non-Producing	291,137	223,436	185,614	160,720	142,738	27.22
Undeveloped	3,294,597	2,037,397	1,264,264	761,172	420,269	7.35
TOTAL PROVED	8,029,035	6,251,799	4,956,690	4,055,107	3,408,669	15.23
PROBABLE	7,772,577	4,445,337	2,843,453	1,970,823	1,449,559	14.13
TOTAL PROVED PLUS PROBABLE	15,801,611	10,697,136	7,800,142	6,025,929	4,858,228	14.81

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2023
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	501,765	754,762	798,250	784,960	755,505
Developed Non-Producing	57,372	47,709	40,777	35,607	31,623
Undeveloped	1,073,560	742,191	525,874	378,815	275,308
TOTAL PROVED	1,632,697	1,544,663	1,364,900	1,199,382	1,062,436
PROBABLE	2,997,861	1,685,195	1,073,160	744,551	549,089
TOTAL PROVED PLUS PROBABLE	4,630,558	3,229,857	2,438,060	1,943,933	1,611,524

UNITED STATES	**AFTER INCOME TAXES DISCOUNTED AT (%/year)[1]**				
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	3,920,245	3,225,267	2,700,252	2,340,482	2,081,978
Developed Non-Producing	221,102	168,193	140,149	122,176	109,348
Undeveloped	1,672,739	941,571	495,199	208,292	17,229
TOTAL PROVED	5,814,085	4,335,031	3,335,600	2,670,950	2,208,555
PROBABLE	3,120,707	1,752,021	1,093,840	741,739	537,024
TOTAL PROVED PLUS PROBABLE	8,934,793	6,087,051	4,429,440	3,412,688	2,745,578

TOTAL	**AFTER INCOME TAXES DISCOUNTED AT (%/year)[1]**				
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	4,422,010	3,980,029	3,498,502	3,125,441	2,837,483
Developed Non-Producing	278,474	215,902	180,926	157,783	140,971
Undeveloped	2,746,299	1,683,763	1,021,073	587,106	292,537
TOTAL PROVED	7,446,783	5,879,693	4,700,500	3,870,331	3,270,990
PROBABLE	6,118,568	3,437,215	2,167,000	1,486,290	1,086,112
TOTAL PROVED PLUS PROBABLE	13,565,351	9,316,908	6,867,500	5,356,621	4,357,103

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, 2023
FORECAST PRICES AND COSTS

($000s)	REVENUE	ROYALTIES	OPERAT-ING COSTS	DEVELOP-MENT COSTS	ABANDON-MENT AND RECLAMA-TION COSTS[1]	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
TOTAL PROVED RESERVES								
Canada	8,003,034	957,947	2,823,801	1,539,394	906,478	1,775,415	142,718	1,632,697
United States	22,445,022	6,554,138	4,795,912	4,446,626	394,728	6,253,619	439,534	5,814,085
Total	30,448,056	7,512,084	7,619,712	5,986,020	1,301,205	8,029,034	582,252	7,446,783
TOTAL PROVED PLUS PROBABLE RESERVES								
Canada	18,207,704	2,742,694	6,045,936	2,895,776	964,984	5,558,315	927,757	4,630,558
United States	33,935,156	9,891,837	7,214,194	6,155,682	430,146	10,243,296	1,308,504	8,934,793
Total	52,142,860	12,634,531	13,260,130	9,051,458	1,395,130	15,801,611	2,236,260	13,565,351

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, 2023
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)	466,084	19.13
	Heavy Crude Oil (including solution gas and associated byproducts)	649,498	14.82
	Bitumen (including solution gas and associated byproducts)	48,034	13.80
	Tight Oil (including solution gas and associated byproducts)	3,111,187	25.33
	Natural Gas (associated and non-associated) (including associated byproducts)	4,268	0.14
	Shale Gas (including associated byproducts)	677,618	6.64
	Total	4,956,689	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and associated byproducts)	866,537	22.64
	Heavy Crude Oil (including solution gas and associated byproducts)	1,157,447	16.26
	Bitumen (including solution gas and associated byproducts)	311,673	7.79
	Tight Oil (including solution gas and associated byproducts)	4,564,916	24.29
	Natural Gas (associated and non-associated) (including associated byproducts)	22,264	0.55
	Shale Gas (including associated byproducts)	877,306	6.45
	Total	7,800,143	

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, 2023 (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							
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	0.8	0.745
2021	68.00	80.35	68.85	3.90	3.55	3.4	0.800
2022	94.80	120.75	99.10	6.40	5.55	6.8	0.770
2023	77.55	100.40	79.60	2.55	2.95	3.9	0.740
Forecast (9)							
2024	73.67	92.91	76.74	2.75	2.20	—	0.752
2025	74.98	95.04	79.77	3.64	3.37	2.0	0.752
2026	76.14	96.07	81.12	4.02	4.05	2.0	0.755
2027	77.66	97.99	82.88	4.10	4.13	2.0	0.755
2028	79.22	99.95	85.04	4.18	4.21	2.0	0.755
2029	80.80	101.94	86.74	4.27	4.30	2.0	0.755
2030	82.42	103.98	88.47	4.35	4.38	2.0	0.755
2031	84.06	106.06	90.24	4.44	4.47	2.0	0.755
2032	85.74	108.18	92.04	4.53	4.56	2.0	0.755
2033	87.46	110.35	93.89	4.62	4.65	2.0	0.755

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 crude 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 Conventional 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 2033 prices and costs escalate at 2.0% annually and the exchange rate remains 0.755.

Weighted average prices realized by us for the year ended December 31, 2023, excluding hedging activities, were $66.14/bbl for heavy crude oil, $67.26/bbl for bitumen, $99.87/bbl for light and medium crude oil, $104.08/bbl for tight oil, $33.94/bbl for NGL, $2.55/Mcf for shale gas and $2.88/Mcf for Conventional natural gas.

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

CANADA	HEAVY CRUDE OIL			BITUMEN		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2022	51,058	34,526	85,584	4,608	45,751	50,359
Extensions	9,402	3,326	12,728	—	—	—
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions	2,176	(5,336)	(3,160)	(261)	25	(236)
Discoveries	—	—	—	—	—	—
Acquisitions	7	2	9	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	741	416	1,157	75	(22)	52
Production	(12,305)	—	(12,305)	(638)	—	(638)
December 31, 2023	51,078	32,935	84,013	3,783	45,754	49,537

CANADA	LIGHT AND MEDIUM CRUDE OIL			TIGHT OIL		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2022	41,951	21,881	63,832	7,005	6,717	13,722
Extensions	2,039	289	2,328	3,012	4,365	7,377
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions [1]	(1,952)	(1,467)	(3,419)	488	93	580
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	(11,417)	(5,772)	(17,188)	—	—	—
Economic Factors	180	65	245	21	22	43
Production	(4,999)	—	(4,999)	(687)	—	(687)
December 31, 2023	25,803	14,997	40,799	9,838	11,197	21,035

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, 2022	7,653	6,340	13,993	19,195	18,798	37,993
nsions	2,449	4,070	6,519	8,254	13,793	22,047
Drilling	—	—	—	—	—	—
oved Recovery	—	—	—	—	—	—
nical Revisions [1]	791	27	817	1,847	222	2,069
veries	—	—	—	—	—	—
isitions	—	—	—	—	—	—
sitions	(14)	(4)	(18)	—	—	—
omic Factors	34	19	52	63	74	136
uction	(807)	—	(807)	(1,402)	—	(1,402)
ber 31, 2023	10,105	10,452	20,557	27,957	32,887	60,844

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, 2022	86,872	45,786	132,658	129,952	125,979	255,931
nsions	1,845	899	2,744	18,585	14,498	33,083
Drilling	—	—	—	—	—	—
oved Recovery	—	—	—	—	—	—
nical Revisions	4,451	(8,835)	(4,384)	2,290	(8,093)	(5,803)
overies	—	—	—	—	—	—
isitions	—	—	—	7	2	9
ositions	(267)	(71)	(338)	(11,475)	(5,787)	(17,262)
omic Factors	928	467	1,395	1,215	590	1,805
uction	(15,919)	—	(15,919)	(22,322)	—	(22,322)
ber 31, 2023	77,910	38,246	116,156	118,252	127,189	245,441

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, 2022	41,558	14,003	55,561	62,112	22,388	84,500
Extensions	18,355	6,285	24,640	6,138	440	6,578
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions [1]	(1,959)	(1,173)	(3,132)	(4,788)	(1,757)	(6,545)
Discoveries	—	—	—	—	—	—
Acquisitions	108,091	54,926	163,017	26,379	10,794	37,172
Dispositions	—	—	—	—	—	—
Economic Factors	5	1	6	3	18	21
Production	(13,106)	—	(13,106)	(5,109)	—	(5,109)
December 31, 2023	152,944	74,041	226,985	84,735	31,882	116,617

D *STATES*	SHALE GAS			OIL EQUIVALENT		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
ber 31, 2022	183,773	65,834	249,607	134,299	47,363	181,662
nsions	32,594	4,686	37,280	29,926	7,506	37,431
Drilling	—	—	—	—	—	—
oved Recovery	—	—	—	—	—	—
nical Revisions [1]	(9,629)	(5,495)	(15,125)	(8,352)	(3,846)	(12,198)
overies	—	—	—	—	—	—
isitions	143,499	53,785	197,284	158,386	74,683	233,069
ositions	—	—	—	—	—	—
omic Factors	23	68	91	12	30	42
uction	(24,293)	—	(24,293)	(22,264)	—	(22,264)
ber 31, 2023	325,967	118,877	444,844	292,007	125,736	417,743

TOTAL	HEAVY CRUDE OIL			BITUMEN		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2022	51,058	34,526	85,584	4,608	45,751	50,359
Extensions	9,402	3,326	12,728	—	—	—
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions	2,176	(5,336)	(3,160)	(261)	25	(236)
Discoveries	—	—	—	—	—	—
Acquisitions	7	2	9	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	741	416	1,157	75	(22)	52
Production	(12,305)	—	(12,305)	(638)	—	(638)
December 31, 2023	51,078	32,935	84,013	3,783	45,754	49,537

TOTAL	LIGHT AND MEDIUM CRUDE OIL			TIGHT OIL		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2022	41,951	21,881	63,832	48,563	20,719	69,283
Extensions	2,039	289	2,328	21,367	10,650	32,017
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions [1]	(1,952)	(1,467)	(3,419)	(1,472)	(1,080)	(2,552)
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	108,091	54,926	163,017
Dispositions	(11,417)	(5,772)	(17,188)	—	—	—
Economic Factors	180	65	245	25	23	49
Production	(4,999)	—	(4,999)	(13,793)	—	(13,793)
December 31, 2023	25,803	14,997	40,799	162,782	85,238	248,020

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, 2022	69,765	28,728	98,493	202,967	84,633	287,600
Extensions	8,587	4,510	13,096	40,849	18,478	59,327
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions [1]	(3,997)	(1,730)	(5,727)	(7,782)	(5,274)	(13,056)
Discoveries	—	—	—	—	—	—
Acquisitions	26,379	10,794	37,172	143,499	53,785	197,284
Dispositions	(14)	(4)	(18)	—	—	—
Economic Factors	36	36	73	86	142	228
Production	(5,916)	—	(5,916)	(25,695)	—	(25,695)
December 31, 2023	94,840	42,334	137,173	353,924	151,764	505,688

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, 2022	86,872	45,786	132,658	264,251	173,342	437,593
Extensions	1,845	899	2,744	48,510	22,004	70,514
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions [1]	4,451	(8,835)	(4,384)	(6,062)	(11,939)	(18,001)
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	158,394	74,685	233,079
Dispositions	(267)	(71)	(338)	(11,475)	(5,787)	(17,262)
Economic Factors	928	467	1,395	1,226	620	1,846
Production	(15,919)	—	(15,919)	(44,586)	—	(44,586)
December 31, 2023	77,910	38,246	116,156	410,259	252,925	663,184

Notes:

(1) Negative technical revisions in light and medium oil are predominantly associated with higher field operating costs in our Viking asset truncating end of life forecasts and actual performance not meeting forecast. Negative technical revisions in tight oil, shale gas and natural gas liquids in our legacy non-operated Eagle Ford assets are predominantly associated with actual performance not meeting forecast and the removal of locations due to inventory consolidation and spacing changes. Negative probable technical revisions in heavy oil are predominantly associated with performance re-characterization of undeveloped locations in the Peace River area. Positive proved technical revisions in heavy oil are predominantly associated with improved performance of producing wells in Peace River, Lloydminster and Peavine areas.

(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 Crude Oil Gross (Mbbl)		Tight Oil Gross (Mbbl)		Heavy Crude 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
2021	2,062	26,781	3,767	26,278	8,208	21,503	—	4,197
2022	1,322	24,814	671	20,757	3,744	20,247	—	3,668
2023	407	15,699	71,679	88,506	4,328	18,445	—	2,105

	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
2021	12,540	37,216	14,415	129,213	4,186	39,431
2022	9,633	25,831	1,503	117,354	842	39,235
2023	769	23,948	93,446	201,607	18,527	54,631

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 Crude Oil Gross (Mbbl)		Tight Oil Gross (Mbbl)		Heavy Crude 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
2021	2,464	16,940	(2,379)	15,839	(330)	21,391	—	45,567
2022	503	16,162	972	14,667	4,425	23,162	—	45,489
2023	247	11,560	55,029	68,578	4,450	21,271	—	45,110

	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
2021	(7,079)	38,947	(10,331)	64,259	(2,904)	20,836
2022	4,535	24,180	2,288	66,653	842	22,175
2023	828	19,672	55,986	118,276	12,638	33,386

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 $1,179 million undiscounted ($269 million discounted at 10 percent). This is comprised of $595 million undiscounted ($66 million discounted at 10 percent) associated with active properties, $313 million undiscounted ($173 million discounted at 10 percent) associated with inactive properties, and $271 million undiscounted ($30 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, 2023
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
2024	272,920	304,942	764,683	764,683	1,037,603	1,069,625
2025	344,836	401,744	911,155	911,155	1,255,992	1,312,899
2026	407,655	516,090	926,320	926,320	1,333,975	1,442,410
2027	220,633	573,732	1,005,901	1,005,901	1,226,534	1,579,633
2028	221,484	415,670	838,566	1,035,629	1,060,050	1,451,299
Remaining	71,867	683,597	—	1,511,994	71,867	2,195,592
Total (undiscounted)	1,539,394	2,895,776	4,446,626	6,155,682	5,986,020	9,051,458

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

Crude oil and natural gas prices are volatile. An extended period of low oil and natural gas prices could have a material adverse effect on the Corporation's business, results of operations, or cash flows and financial condition

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 impacts of geopolitical events, including the Russian Ukrainian war and conflicts in the Middle East, or other adverse economic or political development in the United States, Europe, or Asia, the impact of pandemics/epidemics, government regulation, 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. Additionally, the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. 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 crude oil and heavy crude 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.

There is a also a risk that refining capacity in the U.S. Gulf Coast may be insufficient to refine all of the light sweet crude oil being produced in the U.S. If light sweet crude oil production remains at current levels or continues to increase, demand for the light crude oil production from our U.S. operations could result in widening price discounts to the world crude prices.

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.

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 and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays or failure in obtaining governmental, landowner or other stakeholder 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.

The anticipated benefits of acquisitions may not be achieved and the Corporation may dispose of non-core assets for less than their carrying value on the financial statements

Acquisition of oil and gas properties is a key element of maintaining and growing reserves and production. Competition for these assets has been and will continue to be intense. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive candidates, we may not be able to complete the acquisition or do so on commercially acceptable terms. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses and assets may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Additionally, significant acquisitions can change the nature of our operations and business if acquired properties have substantially different operating and geological characteristics or are

in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited.

Management continually assesses the value and contribution of its Corporation's assets. In this regard, non-core assets may be periodically disposed of so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, may realize less on disposition than their carrying value on the financial statements of the Corporation.

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.

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, GHG emissions regulation (including carbon taxes) enacted in jurisdictions where we operate will impact us. In addition, certain of our assets have a higher GHG emissions intensity than others and may be disproportionately impacted.

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

production, all or part of our production could be subject to costs which are disproportionately higher than those of other producers.

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

Although we provide for the necessary amounts in our annual capital budget to fund our currently estimated obligations, there can be no assurance that we will be able to satisfy our actual future obligations associated with GHG emissions from such funds. 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, drought 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 assets are located where they are exposed to forest fires, floods, heavy rains, hurricanes, drought 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.

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.

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 to 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.

Our operations in the United States are concentrated in the Eagle Ford shale of South Texas and as a result are highly exposed to the gulf coast refining complex and events which negatively impact the functioning of infrastructure in that area, including as a result of weather conditions, terrorism, local

market changes, government regulation and taxation, including limits on the U.S.' ability to export crude oil, 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. Contributions of the existing management team to the immediate and near-term operations of the Corporation are likely to be of central importance. In addition, certain of the Corporation's current employees may have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. 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.

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. At present, the Canadian tax authorities have reassessed the returns of certain of our subsidiaries. For further details, see *"Legal Proceedings and Regulatory Actions"*. Any such reassessment may have an impact on current and future taxes payable. We believe appropriate provisions for current and deferred income taxes have been made in our Financial Statements; however, it is difficult to predict the outcome of audit findings by tax authorities. These findings may increase the amount of our tax liabilities and adversely affect our business, financial condition and results of operations.

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.

We could experience adverse impacts associated with a high concentration of activity and tighter drilling spacing

We are subject to drilling, completion and operating risks, including our ability to efficiently execute large-scale project development, as we could experience delays, curtailments and other adverse impacts associated with a high concentration of activity and tighter drilling spacing. A higher concentration of activity and tighter drilling spacing may increase the frequency of operational shut-ins and unintentional communication with other adjacent wells and reduce the total recoverable reserves from the reservoir.

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.

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 the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, state, provincial and local laws and regulations. Environmental legislation provides for, among other things, the initiation and approval of new oil and natural gas projects, and restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural gas industry operations. In addition, such legislation sets 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. New environmental legislation at the federal, state, and provincial levels may increase uncertainty among oil

and natural gas industry participants as the new laws are implemented, and the effects of the new rules and standards are felt in the oil and natural gas industry. See "*Industry Conditions*".

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liabilities and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it is in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

The Corporation may have to pay certain costs associated with abandonment and reclamation

The Corporation will need to comply with the terms and conditions of environmental and regulatory approvals and all legislation regarding the abandonment of its projects and reclamation of the project lands at the end of their economic life, which may result in substantial abandonment and reclamation costs. Any failure to comply with the terms and conditions of the Corporation's approvals and legislation may result in the imposition of fines and penalties, which may be material. Generally, abandonment and reclamation costs are substantial. The Corporation records a provision for abandonment and reclamation costs in it's financial statements, this provision requires significant judgement and reflects the Corporation's best estimate of the costs to complete the required abandonment and reclamation work. Actual results may be significantly different than the estimated amounts.

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.

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, CSS 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, CSS and waterflooding. If the Corporation is unable to access such water it may not be able to undertake hydraulic fracturing, SAGD, CSS or waterflooding activities, which may reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves.

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.

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.

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 continue to increase. 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, 2023 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.

We are not the operator of a significant portion of our drilling locations in the Eagle Ford 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 a significant portion of our Eagle Ford acreage which is located in the Karnes and Atascosa counties 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.

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: the costs imposed by GHG emissions regulations, 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 in all of its phases. The Corporation competes with numerous other entities in the exploration for, and the development, production and marketing of, oil and natural gas, as well as 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 and have become increasingly dependent upon 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 and reputation

In the normal course of our operations, we may become involved in, be 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, including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, and environmental issues, including claims relating to contamination or 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 effect 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 prior to maturity, 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.

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.

Indigenous Land and Rights Claims

Opposition by Indigenous groups to the conduct of the Corporation's operations, development or exploratory activities in any of the jurisdictions in which the Corporation conducts business may negatively impact it in terms of public perception, diversion of management's time and resources, and legal and other advisory expenses, and could adversely impact the Corporation's progress and ability to explore and develop properties.

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.

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.

Geopolitical risk and conflicts in or around major oil and gas producing nations can significantly impact commodity prices and, therefore the financial condition of the oil and gas industry

Existing or future conflicts in major oil and gas producing nations and the international response may have potential wide-ranging consequences for global market volatility and economic conditions, including affecting crude oil and natural gas prices. Financial and trade sanctions that may be imposed against countries involved in such conflicts may have continued far-reaching effects on the global economy, energy and commodity prices. The short-, medium- and long-term implications of any such conflicts is difficult to predict with any degree of certainty. Depending on the extent, duration, and severity of such conflict(s), it may have the effect of heightening many of the other risks described herein, including, without limitation, risks relating to global market volatility and economic conditions; cybersecurity threats; crude oil and natural gas prices; inflationary pressures, interest rates and costs of capital; and supply chains and cost-effective and timely transportation.

The Corporation could lose its status as a "foreign private issuer" in the United States

The Corporation is required to assess its "foreign private issuer" ("FPI") status under U.S. securities laws on an annual basis at the end of its second quarter. While the Corporation currently qualifies as an FPI, it could lose its FPI status in the future. If the Corporation were to lose its status as an FPI it would be required to fully comply with both U.S. and Canadian securities and accounting requirements applicable to domestic issuers in each country. In addition, if the Corporation loses its FPI status, it would be required to report as a U.S. domestic issuer and be subject to other U.S. securities laws applicable to U.S. domestic issuers. The regulatory and compliance costs to the Corporation under U.S. securities laws as a U.S. domestic issuer may be significantly greater than the costs the Corporation incurs as a foreign private issuer. For example, as a U.S. domestic issuer, the Corporation would be required to file periodic reports and registration statements with the SEC on U.S. domestic issuer forms, which are more detailed and extensive in certain respects than the forms available to the Corporation as a foreign private issuer. The Corporation would also be required to report its oil and gas reserves and production information in accordance with applicable U.S. disclosure requirements. Such conversion and modifications would involve additional costs and may restrict the Corporation's access to capital markets for a period of time until it has satisfied SEC reporting requirements. In addition, the Corporation may lose its ability to rely upon exemptions from certain corporate governance requirements on U.S. stock exchanges that are available to FPIs, which could also increase its costs.

Conflicts of interest may arise between the Corporation and its directors and officers

Circumstances may arise where directors and officers of the Corporation are directors or officers of other companies involved in the oil and gas industry which are in competition to, or otherwise in conflict with, the interests of the Corporation. Directors are required to abstain from voting on matters when they are in conflict. Employees, including officers, are not permitted to partake in activities that do not support the best interests of the Corporation. Where employee conflicts exist, they are to be provided in writing to our Human Resources Department, which discloses all conflicts to Chief Legal Officer. See "*Directors and Officers – Conflicts of Interest*" and the Corporation's Code of Business Conduct and Ethics at www.baytexenergy.com.

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.

Dividends on the Corporation's Common Shares and Common Share repurchases are variable

The future acquisition by the Corporation of Common Shares pursuant to a share buyback (including through its NCIB) and the payment of dividends, if any, and the level thereof is uncertain. Any decision to

acquire Common Shares pursuant to a share buyback or to pay dividends will be subject to the discretion of the Board and may depend on a variety of factors, including, without limitation, the Corporation's business performance, financial condition, financial requirements, commodity prices, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions and satisfaction of the solvency tests imposed on the Corporation under applicable corporate law. In the future, there can be no assurance of the number of Common Shares that the Corporation will acquire pursuant to a share buyback and there can be no assurance that dividends will be paid or, if paid the amount of such dividends.

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 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 energy company insolvencies and the associated financial risk, Alberta and Saskatchewan have expanded their liability management programs to become more stringent in recent years. Additional measures of corporate health, beyond simple asset and liability ratios, are now utilized to determine whether a company can hold, transfer or acquire well licenses. These holistic assessments of companies have reduced the number of parties which can acquire assets. Alberta and Saskatchewan have also introduced mandatory asset retirement obligation spending programs. These programs require a licensee to spend a set percentage of its deemed liability, each year, on abandonment, decommissioning and reclamation.

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, rules 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, rules 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, rules 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 Act, 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, and a commitment pursue efforts to limit any increase to 1.5 degrees. 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. With the release of a joint statement in 2023, both countries reaffirmed their respective commitments and bilateral collaboration in developing and implementing their respective oil and gas methane regulations.

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. In 2022, Canada released its first Emissions Reduction Plan under the Canadian Net-Zero Emissions Accountability Act. It models a pathway to achieving Canada's 2030 target and includes a 42% decrease in oil and gas sectorial emissions from current levels. In 2023, Canada released draft methane regulations for at least a 75 percent reduction in oil and gas methane below 2012 levels by 2030. The Government of Canada has identified capping and cutting oil and gas sector emissions as a priority to achieving its climate commitments. A regulatory framework was released in 2023 proposing a cap-and-trade system for the oil and gas industry under the Canadian Environmental Protection Act. Canadian provincial and federal climate policies, 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 under the Clean Air Act. In August 2022, the Inflation Reduction Act was approved which provides incentives for the implementation of methane mitigation and monitoring activities and proposes a price on methane for oil and gas facilities above a threshold. Final rules to reduce methane and other air pollutants from the oil and gas sector was released in December 2023. It is expected to result in a nearly 80 percent reduction in methane emissions from 2024 to 2038.

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 carbon pollution pricing system. 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. Emissions coverage includes stationary combustion from the implementation of the performance standards and expanding coverage to stationary combustion and flaring emissions in 2023.

Carbon pricing in Canada is currently set to $65 per tCO2e in 2023 and escalates $15 per tCO2e annually to $170 per tCO2e 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 2022, regulatory reviews were completed on the provincial standards that outline the compliance rates and carbon pricing out to 2030.

In the Province of Saskatchewan, the Output-Based Performance Standard regulation applies to facilities emitting more than 25,000 tCO2e. 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. As a result our operated facilities are not subject to the federal carbon pollution pricing system. This provincial program requires a 8.33 percent reduction for 2023 and escalates 1.67% annually to an anticipated total 20% reduction by 2030, when compared to a 2019 baseline for stationary combustion and a 2020-2022 baseline for flaring. To the extent a company does not meet the required compliance rate reduction, annual compliance fees apply to the excess regulated emissions. The province matches the federal carbon pricing schedule out to 2030 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 tCO2e. 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 and escalates 2% per year starting in 2023 to an anticipated 26% for fuel and 24% for flaring by 2030. To the extent a company does not meet the required reduction, annual compliance fees apply to the excess regulated emissions. The province matches the federal carbon pricing schedule out to 2030 and applies this price to the excess emissions. Regulatory compliance offset credits are generated in the provincial compliance programs if emissions are reduced beyond the annual compliance rate reduction requirement.

In 2022, the Inflation Reduction Act was passed into law in the United States. It imposes a fee on the emissions of methane from the oil and gas sector above a threshold. Beginning in 2024, the Waste Emission Charge on excess methane is proposed at US$36 per tonne of CO_2e ($900 per tonne of methane) rising to US$48 per tonne of CO_2e ($1,200 per tonne of methane) in 2025, and US$60 per tonne of CO_2e ($1,500 per tonne of methane) in 2026 and thereafter.

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. The Government of Canada has committed to expanding its oil and gas methane emissions reduction target to at least a 75% reduction below 2012 levels by 2030. In December 2023, a draft federal methane regulations for the oil and gas sector were released to achieve the 2030 target.

In the United States, air contaminants are the focus of current federal and Texas state standards, while methane rules are limited to new, modified, or reconstructed sites. In 2021, the EPA released its first methane proposal with final rules released in December 2023. It outlines nationwide emissions guidelines for states to limit methane emission from oil and gas. The development of state level plans or challenges to the finalized federal rules are anticipated.

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 applicable 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 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

The Corporation began paying regular dividends to Shareholders on a quarterly basis as a part of the Corporation's return of capital framework announced in connection with the Ranger Merger. Commencing in third quarter of 2023, the Corporation began paying a quarterly dividend on the first business day of each quarter to Shareholders of record on the 15th day of the month prior to the payment date.

Although the Corporation strives to maintain consistent dividend payments, the amount of cash dividends to be paid on the Common Shares, if any, will be subject to the discretion of the Board of Directors and may vary depending on a variety of factors, including fluctuations in the price of oil and gas, exchange rates and production rates, reserves growth, the size of development drilling programs and the portion thereof funded from cash flow and the overall level of debt and working capital of the Corporation, the prevailing economic and competitive environment, the taxability of Baytex, Baytex's ability to raise capital, the amount of capital expenditures, the satisfaction of solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends and other conditions existing from time to time. There can be no guarantee that Baytex will maintain the quantum or frequency of its dividends.

The agreements governing the Credit Facilities and Senior Notes provide that distributions to Shareholders and share repurchases are not permitted if the Corporation is in default under the agreements or the payment of such distribution would cause an event of default.

The following table sets forth the amount of cash dividends declared per Common Share by the Corporation for the periods indicated.

Declaration Date	Dividend $ per Common Share
July 27, 2023	0.0225
November 2, 2023	0.0225

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.sedarplus.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 Common 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 February 5, 2020, we issued US$500 million aggregate principal amount of 2027 Notes bearing interest at a rate of 8.75% per annum payable semi-annually. The 2027 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. As a result of repurchases and cancellations, as at December 31, 2023 US$410 million principal amount of the 2027 Notes remain outstanding.

On April 27, 2023, we issued US$800 million aggregate principal amount of 2030 Notes bearing interest at a rate of 8.50% per annum payable semi-annually. The 2030 Notes were issued at 98.709% of par and are redeemable at our option, in whole or in part, at specified redemption prices after April 30, 2026 and will be redeemable at par from April 30, 2028 to maturity.

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

Credit Facilities

Our Credit Facilities consist of US$1.1 billion of revolving credit facilities comprised of: (i) a US$50 million operating loan and a US$750 million syndicated revolving loan for Baytex; and (ii) a US$45 million operating loan and a US$255 million syndicated revolving loan for Baytex USA. The Credit Facilities are secured and, unless extended by the lenders, will mature on April 1, 2026.
For additional details regarding the covenants in our Credit Facilities and our compliance therewith, see the Baytex Annual 2023 MD&A . Also see *"Material Contracts"*.

Escrowed Securities and Securities Subject to Contractual Restriction

As at December 31, 2022, 56,297,330 Common Shares were subject to contractual restrictions on transfer as outlined in the table below.

Designation of Class	Number of Securities	% of Class
Common Shares (1)	56,297,330	6.85%

Note:

(1) All 56,297,330 of the restricted Common Shares are subject to a hold period agreement with an end date of March 16, 2024.

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+	Ba3	B+
Senior Unsecured Debt (Senior Notes)	BB-	B1	BB-

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. Other than the foregoing, no other payments were made to S&P, Moody's or Fitch in respect of any other service provided to the Corporation by such organization during the last two years.

MARKET FOR SECURITIES

The Common Shares are listed and trade on the TSX and the NYSE 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. The Common Shares began trading on the NYSE on February 23, 2023.

	Canada TSX Trading			Canada Composite Trading			US NYSE Trading		
	Price Range			Price Range			Price Range		
	High ($)	Low ($)	Volume Traded	High ($)	Low ($)	Volume Traded	High (US$)	Low (US$)	Volume Traded
2023									
January	6.16	5.54	54,957,236	6.16	5.54	98,934,966	4.63	4.1	5,098,258
February	6.17	5.26	76,926,419	6.17	5.26	143,237,173	4.625	3.87	23,937,189
March	5.64	4.37	145,405,501	5.68	4.37	247,339,258	4.15	3.2	74,766,072
April	5.45	4.92	68,237,598	5.45	4.92	131,864,314	4.09	3.6	30,921,285
May	5.05	4.28	70,709,931	5.05	4.28	142,786,494	3.56	3.16	43,163,142
June	4.71	3.90	123,971,487	4.71	3.93	240,182,633	3.54	2.95	170,503,250
July	5.32	4.22	91,400,930	5.32	4.22	162,375,368	4.04	3.14	109,838,821
August	5.60	5.21	81,261,554	5.60	5.21	149,677,283	4.18	3.81	90,491,260
September	5.99	5.44	107,288,759	5.99	5.44	197,607,527	4.41	4.02	198,673,606
October	6.31	5.26	111,895,613	6.31	5.26	224,783,940	4.6	3.83	180,091,993
November	6.23	5.16	114,937,885	6.24	5.16	213,024,495	4.53	3.77	206,170,230
December	5.14	4.20	96,131,695	5.14	4.20	193,527,280	3.64	3.1	168,641,816

DIRECTORS AND OFFICERS

Directors of the Corporation

The following table sets forth the name, municipality of residence, age as at December 31, 2023, 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	64	November 2017	Corporate director.
Tiffany Thom Cepak [3][5] Friendswood, Texas	52	June 2023	Corporate director.
Trudy M. Curran [2][4] Calgary, Alberta	61	July 2016	Corporate director. Previously, Interim Chief Executive Officer and managing director of Riversdale Resources from February 2019 to June 2019.
Eric T. Greager Denver, Colorado	54	November 2022	President and Chief Executive Officer of the Corporation since November 2022. Previously the President and Chief Executive Officer of Civitas Resources (formerly Bonanza Creek Energy, Inc.) from April 2018 to February 2022.
Don G. Hrap [3][5] Houston, Texas	64	March 2020	Corporate director.
Angela S. Lekatsas [4][5] Calgary, Alberta	62	February 2023	Corporate director. Previously, Chief Executive Officer of Cervus Equipment Corporation from May 2019 to October 2021 and prior thereto a director since October 2013.
Jennifer A. Maki [2][5] North York, Ontario	53	September 2019	Corporate director.
David L. Pearce [2][3] Calgary, Alberta	69	August 2018	Deputy Chairman, Azimuth Capital Management.
Stephen D.L. Reynish [3][4] Calgary, Alberta	65	November 2020	Corporate director. Previously, President and Chief Executive Officer of Enlighten Innovations from October 2020 until October 2022. Formerly Executive Vice President at Suncor Energy Inc. from 2012 until 2020.
Jeffery Wojahn [2][4] Denver, Colorado	61	June 2023	Corporate director. Previously, co-founder and Executive Chairman of MiddleFork Energy Partners, a privately held exploration and production company, from 2017 to 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, 2023, 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
Eric T. Greager Denver, Colorado	54	November 2022	President and Chief Executive Officer of the Corporation since November 2022. Previously the President and Chief Executive Officer of Civitas Resources (formerly Bonanza Creek Energy, Inc.) from April 2018 to February 2022.
Chad L. Kalmakoff Calgary, Alberta	47	Chief Financial Officer	Chief Financial Officer of the Corporation since November 2022. Prior thereto, Vice President, Finance of the Corporation since September 2015.
Chad E. Lundberg Calgary, Alberta	42	Chief Operating Officer	Chief Operating Officer of the Corporation since June 2023. Prior thereto Chief Operating & Sustainability Officer since July 2021. Prior thereto Vice President, Light Oil since December 2018.
James R. Maclean Calgary, Alberta	44	Chief Legal Officer and Corporate Secretary	Chief Legal Officer and Corporate Secretary of the Corporation since June 2023. Prior thereto Vice President, General Counsel and Corporate Secretary since February 2022. Prior thereto General Counsel and Corporate Secretary since August 2018.
Brian G. Ector Calgary, Alberta	55	SVP, Capital Markets and Investor Relations	SVP, Capital Markets and Investor Relations of the Corporation since June 2023. Prior thereto Vice President, Capital Markets since August 2018. Prior thereto, an officer of the Corporation since June 2011.
Kendall D. Arthur Calgary, Alberta	43	SVP and General Manager, Cdn. Heavy Oil Operations	SVP and General Manager, Cdn. Heavy Oil Operations of the Corporation since June 2023. Prior thereto Vice President, Heavy Oil of the Corporation since December 2018. Prior thereto, a business unit Vice President with the Corporation since January 2012.
Julia Gwaltney Houston, Texas	52	SVP and General Manager, US Eagle Ford Operations	SVP and General Manager, US Eagle Ford Operations since June 2023. Previously, the SVP & Chief Operating Officer of Ranger Oil Corporation since January 2021. Additionally, served as Chief Operating Officer of Gary Permian, LLC, from November 2015 to January 2020.

Name and Municipality of Residence	Age	Office	Principal Occupation for Past Five Years
Nicole Frechette Calgary, Alberta	40	VP and General Manager, Cdn. Light Oil Operations	VP and General Manager, Cdn. Light Oil Operations of the Corporation since June 2023. Prior thereto 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.
Chris M.P. Lessoway Calgary, Alberta	39	VP, Finance & Treasurer	Vice President of Finance and Treasurer of the Corporation since June 2023. Prior thereto Financial Controller starting from June 2017.

Ownership of Securities by Management

As at the date of this AIF, the directors and officers of Baytex, as a group, beneficially owned, or controlled or directed, directly or indirectly, 4,957,497 Common Shares.

Conflicts of Interest

Certain of the directors and officers named above may be directors or officers of issuers or other companies which are in competition with the Corporation, and as such may encounter conflicts of interest in the administration of their duties with respect to the Corporation. In situations where conflicts of interest arise, the Corporation expects the applicable director or officer to declare the conflict and, if a director of the Corporation, abstain from voting in respect of such matters on behalf of the Corporation.

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.

David Pearce is a director of Courser Energy Ltd. formerly Kaisen Energy Corp. ("Kaisen"). On December 8, 2021, Kaisen sought and obtained protection under the Companies' Creditors Arrangement Act

("CCAA") pursuant to an Order (the "Initial Order") of the Court of Queen's Bench of Alberta (the "Court"). The Initial Order authorized Kaisen to begin a Court-supervised restructuring and granted Kaisen various relief, including but not limited to, an initial stay of proceedings against Kaisen and its assets, appointing Ernst & Young Inc. as Monitor (the "Monitor"), and providing Kaisen the opportunity to prepare and file a plan of arrangement under the CCAA for the consideration of its creditors and other stakeholders. On December 17, 2021, the Court approved a plan of arrangement under the CCAA including provisions relating to receiving creditor and stakeholder approval for the plan of arrangement. On March 16, 2022, the Monitor filed a Plan Implementation Certificate confirming that the Plan, as approved by affected creditors and the Court is effective in accordance with its terms and the Sanction Order. As a result, the CCAA proceedings have now concluded and the Monitor has been discharged.

Trudy Curran, a director of Baytex, was a director of Great Panther Mining Ltd. (“Great Panther”) from June 9, 2021 to December 15, 2022. On September 6, 2022, Great Panther filed a notice of intention to make a proposal under the Bankruptcy and Insolvency Act (Canada), which provided Great Panther with creditor protection while it sought to restructure its affairs. On November 18, 2022, the British Columbia Securities Commission issued a cease trade order in respect of Great Panther’s securities as a result of its inability to file its quarterly continuous disclosure documents in accordance with Canadian securities laws. On December 16, 2022, Great Panther made a voluntary assignment into bankruptcy under the Bankruptcy and Insolvency Act (Canada) and Alvarez & Marsal Canada Inc. was appointed licensed insolvency trustee of Great Panther's estate.

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.

Our audit committee is responsible for reviewing all related party transactions and its mandate specifies that the audit committee is responsible for ensuring the nature and extent of such transactions are properly disclosed.

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 to this AIF.

Composition of the Audit Committee

The members of our Audit Committee are Jennifer A. Maki, Don G. Hrap, Angela S. Lekatsas and Tiffany Thom Cepak. The relevant education and experience of each Audit Committee member is outlined below:

Name	Relevant Education and Experience
Jennifer A. Maki [(1)(2)(3)] *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 [(1)(2)]	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.
Angela S. Lekatsas [(1)(2)(3)]	Bachelor of Commerce Degree (Major in Accounting) from the University of Saskatchewan, post-graduate Chartered Professional Accountant designation from the Institute of Chartered Accountants of Alberta, and U.S. Certified Public Accountant equivalency from the Illinois Board of Examiners (inactive). She also holds the ICD.D designation from the Institute of Corporate Directors. Ms. Lekatsas spent 20 years in industry as the former President and CEO of Cervus Equipment Corporation and served in various executive roles with Nutrien Inc. and its predecessor company Agrium Inc. Prior thereto Ms. Lekatsas practiced public accounting for 16 years during which time she advocated for the accounting and auditing profession in various provinces sitting on Institute Committees such as the Professional Conduct and Financial Institutions Committees, acting as a guest lecturer as well sitting as an elected member of the ICAM Board
Tiffany Thom Cepak [(1)(2)(3)]	Ms. Cepak holds a B.S. in Engineering from the University of Illinois and a Master of Business Administration in Management with a concentration in Finance from Tulane University. Formerly served as Chief Financial Officer for Energy XXI Gulf Coast Inc., from August 2017 to October 2018. Prior to that, a CFO at KLR Energy Acquisition Corp., from January 2015 to June 2017. Additionally, the CFO of EPL Oil & Gas, Inc. for four years until it was sold in 2014.

Notes:

(1) Independent director.

(2) Financially literate within the meaning of National Instrument 52-110 - Audit Committees and the NYSE listing standards.

(3) An "Audit Committee Financial Expert" pursuant to the SEC's definition of the term.

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 2023 and 2022:

Year	Audit Fees [(1)]	Audit-Related Fees [(2)]	Tax Fees [(3)]	All Other Fees [(4)]	Total
2023	$ 2,234	$ —	$ —	$ —	$ 2,234
2022	$ 1,145	$ —	$ —	$ —	$ 1,145

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 2023 and 2022 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

Other than as disclosed below, 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.

In June 2016, certain indirect subsidiary entities received reassessments from the CRA that deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. Following objections and submissions, in November 2023 the CRA issued notices of confirmation regarding their prior reassessments. In February 2024, Baytex filed notices of appeal with the Tax Court of Canada and we estimate it could take between two and three years to receive a judgment. The reassessments do not require us to pay any amounts in order to participate in the appeals process. 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.

We remain confident that the tax filings of the affected entities are correct and are vigorously defending our tax filing positions. In addition, we have purchased $272.5 million of insurance coverage to help manage the litigation risk associated with this matter. The expenses incurred to purchase the insurance coverage were approximately $51 million. The most recent reassessments issued by the CRA assert taxes owing by the trusts (described below) of $244.8 million, late payment interest of $166.6 million and a late filing penalty in respect of the 2011 tax year of $4.1 million.

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 deducted in computing the taxable income of those trusts. The reassessments, as confirmed in November 2023, disallow the deduction of the Losses for two reasons. Firstly, the reassessments allege that (i) the trusts were resettled, and (ii) the resulting successor trusts were not able to access the losses of the predecessor trusts. Secondly, the reassessments allege that the general anti-avoidance rule of the *Income Tax Act* (Canada) operates to deny the deduction of the losses. If, after exhausting available appeals, the deduction of Losses continues to be disallowed, either the trusts or their corporate beneficiary will owe cash taxes, late payment interest and potentially penalties. The amount of cash taxes owing, late payment interest and potential penalties are dependent upon the taxpayer(s) ultimately liable (the trusts or their corporate beneficiary) and the amount of unused tax shelter available to those/that taxpayer(s) to offset the reassessed income, including tax shelter from future years that may be carried back and applied to prior years.

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 senior 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 third amended and restated credit agreement in respect of the Credit Facilities and the subsequent clarification amending agreement (both filed on SEDAR+ on January 11, 2024) ;

b. 2020 Debt Indenture (filed on SEDAR+ on February 10, 2020);

c. 2023 Debt Indenture (filed on SEDAR+ on April 28, 2023);

d. our share award incentive plan (filed on SEDAR+ on April 18, 2016) and our subsequently amended share award incentive plan (filed on January 28, 2018, March 1, 2022 and February 23, 2023) and

e. our investor and registration rights agreement (filed on SEDAR+ on March 1, 2023).

Copies of each of these contracts are accessible on the SEDAR+ website at *www.sedarplus.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.sedarplus.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. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2023 and the related Baytex Annual 2023 MD&A which are accessible on the SEDAR+ website at *www.sedarplus.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) *"Eric T. Greager"*
Eric T. Greager
President and Chief Executive Officer

(signed) *"Chad L. Kalmakoff"*
Chad L. Kalmakoff
Chief Financial Officer

(signed) *"Don G. Hrap"*
Don G. Hrap
Director and Chair of the Reserves and Sustainability Committee

(signed) *"David L. Pearce"*
David L Pearce
Director and Member of the Reserves and Sustainability Committee

February 28, 2024

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 the Company's reserves data as at December 31, 2023. The reserves data is an estimate of proved reserves and probable reserves and related future net revenue as at December 31, 2023 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 net present value of 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, 2023, and identifies the respective portions thereof that we have evaluated and reported on to Company's Board of Directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation 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, 2023	Canada	—	2,888,697.3	—	2,888,697.3
McDaniel & Associates	December 31, 2023	United States	—	4,911,444.8	—	4,911,444.8
TOTALS				7,800,142.1		7,800,142.1

6. In our opinion, the reserves data respectively 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 1, 2024

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 determining, in its capacity as a committee of 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 assist the Board in monitoring and overseeing:

1. the preparation and disclosure of the financial statements of the Corporation and related matters;
2. communication between directors and the external auditors;
3. the external auditors' qualifications and independence;
4. compliance with legal and regulatory requirements;
5. the performance of the Corporation's external auditor;
6. the integrity, credibility and objectivity of financial reports and statements; and
7. the relationship among the Committee, all independent directors, 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" and the laws, rules and regulations of the U.S. Securities and Exchange Commission ("SEC") and the New York Stock Exchange ("NYSE"), as applicable, subject to any permitted phase-in periods that may apply. The members of the Committee shall be appointed by the Board from time to time based on the recommendation of the Nominating & Governance Committee.

2. At least one member of the Committee shall have accounting or related financial management expertise, as the Board interprets such qualification in its business judgment. For certainty, any member of the Committee that qualifies as an "audit committee financial expert" under the rules of the SEC will be deemed to meet this requirement. Members of the Committee may not be "affiliates" of the Corporation or any subsidiary of the Corporation. Subject to any permitted exceptions, members of the Committee may not accept, directly or indirectly, any consulting, advisory, or other compensatory fee from the Corporation or any subsidiary thereof. Corporation

3. A member of the Committee may not simultaneously serve on the audit committees of more than three public companies, unless the Board first determines that such simultaneous service would not impair the ability of such member to effectively serve on the Committee. Any such determination must be publicly disclosed in accordance with the rules of the NYSE.

4. The Board shall appoint a Chair of the Committee, who shall be an independent director.

5. 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:
    a. recommend the firm of chartered accountants to be nominated as the Corporation's auditors, for approval by the shareholders of the Corporation; and
    b. oversee the planning and staffing of the audit by the external auditor. 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:
    a. identifying, monitoring and mitigating business risks; and
    b. ensuring compliance with legal, ethical and regulatory requirements.

3. It is a primary responsibility of the Committee to review with management and the external auditors the interim and annual financial statements of the Corporation, including disclosures made under "Management's Discussion and Analysis", prior to their submission to the Board for approval. The review process should include, without limitation:
    a. reviewing major issues regarding accounting policies and principles and financial statement presentations, including any changes in accounting principles, or in their application;
    b. reviewing major issues as to the adequacy of the Corporation's internal controls and any special audit steps adopted in light of material control deficiencies;
    c. reviewing significant management judgments, estimates and assumptions that affect the application of accounting policies and their reported amounts;
    d. reviewing analyses prepared by management and/or the external auditors setting forth significant financial reporting issues and judgments made in connection with the preparation of the financial statements, including analyses of the effects of alternative GAAP methods on the financial statements;
    e. reviewing accounting treatment of unusual or non-recurring transactions;
    f. ascertaining compliance with covenants under loan agreements;
    g. reviewing disclosure requirements for commitments and contingencies;
    h. reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
    i. reviewing unresolved differences between management and the external auditors;
    j. reviewing the type and presentation of information to be included in the Corporation's earnings press releases (paying particular attention to any use of "pro forma" or "adjusted" non-GAAP information prior to their public release);
    k. reviewing the effect of regulatory and accounting initiatives, as well as off-balance sheet structures, on the financial statements of the Corporation;
    l. obtaining explanations of significant variances with comparative reporting periods; and
    m. 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, earnings press releases, the annual information form and any annual report filed with the U.S. Securities and Exchange Commission. 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. The Committee shall discuss the Corporation's earnings press releases, as well as financial information and earnings guidance provided to analysts and rating agencies, recognizing that this review and discussion may be done generally (consisting of a discussion of the types of information to be disclosed and the types of presentations to be made).

6. With respect to the external auditors of the Corporation, the Committee shall:
    a. in its capacity as a committee of the Board, be directly responsible for the compensation, retention and oversight of the work of the external auditors (including resolution of disagreements between management and the auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the listed issuer, including the terms of their engagement for the integrated audit;
    b. review and approve any other services to be provided by the external auditors (including the fee for such services) as detailed below;
    c. 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;
    d. at least annually, review the qualifications, performance and independence of the external auditors including a) review the experience and qualifications of the senior members of the external auditors' team; b) confirm with the external auditors that it is in compliance with applicable legal, regulatory and professional standards relating to auditor independence; c) review annual reports from the external auditors regarding its independence and consider whether there are any non-audit services or relationships that may affect the objectivity and independence of the external auditors and, if so, recommend to the Board to take appropriate action to satisfy itself of the independence of the external auditor; and obtain and review such reports from the external auditors as may be required by applicable legal and regulatory requirements;
    e. at least annually, obtain and review a report by the external auditors describing the firm's internal quality-control procedures; any material issues raised by the most recent internal quality-control review, or peer review, of the firm, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the firm, and any steps taken to deal with any such issues; and (to assess the external auditors' independence) all relationships between the external auditors and the Corporation;
    f. review with the external auditors any problems or difficulties the external auditors may have encountered during the provision of its audit services and management's response, including any restrictions on the scope of activities or access to the requested information and any significant disagreements with management;
    g. review and evaluate the lead partner of the external auditor;
    h. ensure the regular rotation of the lead audit partner as required by law, and consider whether, in order to assure continuing external auditor independence, there should be regular rotation of the audit firm itself. The Committee should present its conclusions with respect to the external auditors to the full Board.

7. Periodically review with management the need for an internal audit function.

8. Review with the external auditors 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.

9. 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 applicable laws, rules and regulations and such other procedures as may be established by the Committee from time to time.

10. The Committee shall review the risk assessment and 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:

    a. 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;

    b. the insurance coverages maintained by the Corporation;
    c. 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

    d. 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.

11. 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.

12. 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.

13. 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.

14. The Committee shall forthwith report any issues arising in connection with its duties, the results of meetings and reviews undertaken and any associated recommendations to the Board.

15. 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 Chair of the meeting shall not 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 Chair 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 Chair 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 Audit Committee shall meet periodically with management and the independent auditor in separate executive sessions.

9. The Committee shall conduct an annual evaluation of its performance in fulfilling its duties and responsibilities under this mandate, and shall assess the adequacy of the reporting and information provided by management to support the Committee's oversight responsibilities.

10. The Committee may retain persons having special expertise and/or obtain independent professional advice, including, without limitation, independent counsel or other advisors, as it determines necessary to carry out its duties, at the expense of the Corporation.

11. The Corporation shall provide appropriate funding, as determined by the Committee, in its capacity as a committee of the Board, for payment of (i) compensation to any external auditors engaged for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation; (ii) compensation to any advisors employed by the Committee; and (iii) ordinary administrative expenses of the Committee that are necessary or appropriate in carrying out its duties.

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

13. 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 February 13, 2023

Exhibit 99.2

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 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, 2023, our internal control over financial reporting was effective. As permitted by applicable securities laws in Canada and the U.S., management excluded from its design and assessment the internal control over financial reporting for Ranger Oil Corporation ("Ranger"), which was acquired on June 20, 2023. The consolidated financial statements as at and for the year ended December 31, 2023 include $3.5 billion of total assets and $691.9 million of revenues, net of royalties from the acquired entity.

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, 2023 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, 2023.

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/ Eric T. Greager

Eric T. Greager
President and Chief Executive Officer
Baytex Energy Corp.

/s/ Chad L. Kalmakoff

Chad L. Kalmakoff
Chief Financial Officer
Baytex Energy Corp.

February 28, 2024

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, 2023 and 2022, 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, 2023 and 2022, 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, 2023, 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 28, 2024 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

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

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

Critical Audit Matters

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

Assessment of the recoverable amount of oil and gas properties

As discussed in note 7 to the consolidated financial statements, the Company identified indicators of impairment as of December 31, 2023 related to the Company's Viking and Eagle Ford Non-op cash generating units (CGUs). The Company therefore determined the recoverable amount as of December 31, 2023 of each of the CGUs and recorded an impairment of $833.7 million. 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 cash flows") and the discount rate. The estimation of CGU reserves cash flows in the reserve report involves the expertise of independent qualified reserve evaluators, who take into consideration assumptions related to forecasted production volumes, royalty obligations, operating and capital costs and commodity prices (collectively "CGU reserve report assumptions"). The Company engages independent qualified reserve evaluators to estimate CGU reserves cash flows.

We identified the assessment of the recoverable amount of the Viking and Eagle Ford Non-op CGUs as a critical audit matter. Changes in CGU reserve report assumptions and discount rates could have had a significant impact on the estimate of recoverable amounts and the resulting impairment in the carrying amount of oil and gas properties relating to the CGUs. A high degree of auditor judgment was required to evaluate the Company's estimates of CGU reserves cash flows, and related CGU reserve report assumptions, and the discount rates, which were inputs into the calculation of recoverable amounts. Additionally, the evaluation of these recoverable amounts 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 the CGU reserve report assumptions and resulting CGU reserves cash flows.

We evaluated the competence, capabilities and objectivity of the independent qualified reserve evaluators engaged by the Company, who estimated the CGU reserves cash flows. We evaluated the methodology used by the independent qualified reserves evaluators to estimate the CGU reserves cash flows for compliance with the applicable regulatory standards. We compared the current year actual CGU production volumes, royalty obligations, 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 cash flows by comparing them to those published by other reserve engineering companies. We assessed the forecasted production volumes, royalty obligations, operating and capital costs assumptions used in the current year estimate of the CGU reserves cash flows 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 inputs of the discount rates against publicly available market data for comparable assets and assessing the resulting discount rates
- evaluating the Company's estimate of recoverable amount of the CGUs by comparing to publicly available market data and valuation metrics for comparable entities.

Fair value measurement of oil and gas properties in a business combination

As discussed in note 4 to the consolidated financial statements, the Company acquired Ranger Oil Corporation ("Ranger") in a business combination that was completed on June 20, 2023 (the "acquisition-date"). As a result of the transaction, the Company acquired oil and gas properties with an acquisition-date fair value of $3,096.4 million, a portion of which related to oil and gas properties with proved and probable oil and gas reserves. The determination of the acquisition-date fair value of the oil and gas properties with proved and probable oil and gas reserves involves numerous estimates, including cash flows associated with estimated acquired proved and probable oil and gas reserves ("acquired reserves cash flows") and the discount rate. The estimation of acquired reserves cash flows in the acquired reserve report involves the expertise of the independent qualified reserve evaluators, who take into consideration assumptions related to forecasted production volumes, royalty obligations, operating and capital costs and commodity prices (collectively "acquired reserve report assumptions"). The Company engages independent qualified reserve evaluators to estimate the acquired reserves cash flows.

We identified the determination of the acquisition-date fair value of the oil and gas properties acquired in the Ranger business combination as a critical audit matter. Changes in acquired reserve report assumptions and the discount rate could have had a significant impact on the determination of the acquisition-date fair value of the acquired oil and gas properties. A high degree of auditor judgment was required to evaluate the acquired reserve report assumptions and the discount rate, which were inputs into the determination of the acquisition-date fair value. Additionally, the evaluation of this fair value 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 this critical audit matter. This included controls related to:

- the Company's determination of the fair value, including the discount rate
- the Company's determination of the acquired reserve report assumptions and resulting acquired reserves cash flows.

We evaluated the competence, capabilities and objectivity of the independent qualified reserve evaluators engaged by the Company, who estimated the acquired reserves cash flows. We evaluated the methodology used by the independent qualified reserve evaluators to estimate the acquired reserves cash flows for compliance with the applicable regulatory standards. We assessed the forecasted commodity prices used in the acquired reserve report by comparing them to those published by other reserve engineering companies. We assessed the forecasted production volumes, royalty obligations, operating and capital costs assumptions used in the acquired reserve report by comparing them to 2023 historical results for the Ranger oil and gas properties post-acquisition and the Ranger reserve report assumptions.

We involved valuation professionals with specialized skills and knowledge, who assisted in:

- evaluating the Company's determination of the discount rate by comparing the inputs of the discount rate against publicly available market data for comparable assets and assessed the resulting discount rate
- evaluating the Company's estimate of the acquisition-date fair value of the acquired oil and gas properties by comparing to publicly available market data and valuation metrics for comparable entities.

Assessment of indicators of impairment related to the Eagle Ford Operated CGU

As discussed in notes 2 and 7 to the consolidated financial statements, the Company assesses its oil and gas properties by cash generating unit ("CGU") for indicators of impairment and impairment reversal at the end of each reporting period. These indicators can be internal such as changes in estimated proved and probable oil and gas reserves ("CGU reserves cash flows") and internally estimated oil and gas resources ("CGU resources cash flows"), or external such as market conditions impacting discount rates or market capitalization. The estimation of CGU reserves cash flows in the reserve report involves the expertise of independent qualified reserve evaluators, who take into consideration assumptions related to forecasted production volumes, royalty obligations, operating and capital costs and commodity prices ("CGU reserve report assumptions"). The estimation of CGU resources cash flows involves the expertise of internal qualified reserve evaluators, who take into consideration

assumptions related to forecasted production volumes, royalty obligations, operating and capital costs and commodity prices (collectively "CGU resource report assumptions"), in addition to the number and locations of development wells along with the annual drilling timeline and pace. Based on the Company's assessment of internal and external indicators of impairment, the Company determined that impairment testing was not required for the Eagle Ford Operated CGU as of December 31, 2023.

We identified the assessment of indicators of impairment related to the Eagle Ford Operated CGU as a critical audit matter. Indicators of impairment and impairment reversal such as changes in estimated CGU reserves cash flows and CGU resources cash flows required the application of auditor judgement. A high degree of auditor judgment was required in evaluating the Eagle Ford Operated CGU reserve report assumptions and CGU resource report assumptions, which were used in the assessment of indicators of impairment. Additionally, the evaluation of the Company's resource valuation metric derived from the CGU resources cash flows required the 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 assessment of internal and external indicators of impairment for the Eagle Ford Operated CGU
- the Company's estimation of the Eagle Ford Operated CGU reserves cash flows and CGU resources cash flows and related CGU reserve report assumptions and CGU resource report assumptions in addition to the number and locations of development wells along with the annual drilling timeline and pace.

We evaluated the Company's assessment of internal and external indicators of impairment for the Eagle Ford Operated CGU by considering whether the quantitative and qualitative information in the analysis was consistent with external market and industry data and the estimate of Eagle Ford Operated CGU reserves cash flows and CGU resources cash flows.

We evaluated the competence, capabilities and objectivity of the independent qualified reserve evaluators engaged by the Company. We evaluated the methodology used by the independent qualified reserves evaluators to estimate Eagle Ford Operated CGU reserves cash flows for compliance with the applicable regulatory standards. We compared 2023 actual production volumes, royalty obligations, operating and capital costs to those assumptions used in the acquired reserve report estimate of proved and probable reserves for the Eagle Ford Operated CGU to assess the Company's ability to accurately forecast. We assessed the forecasted commodity prices used in the estimate of the Eagle Ford Operated CGU reserves cash flows by comparing them to those published by other reserve engineering companies. We assessed the forecasted production volumes, royalty obligations, operating and capital costs assumptions used in the estimate of Eagle Ford Operated CGU reserves cash flows by comparing them to historical results.

We evaluated the competence, capabilities and objectivity of the internal qualified reserve evaluators. We assessed the forecasted production volumes, royalty obligations, operating and capital costs and commodity price assumptions for development well locations in the Eagle Ford Operated CGU resource report by comparing to the CGU reserve report assumptions for similar well locations in the Eagle Ford Operated CGU reserve report. We assessed the number and locations of development wells in the Eagle Ford Operated CGU resource report by comparing to the number and locations of development wells in the Eagle Ford Operated CGU full field development plan. We assessed the annual drilling timeline and pace in the Eagle Ford Operated CGU resource report by comparing to the annual drilling timeline and pace in the Eagle Ford Operated CGU reserve report.

We involved valuation professionals with specialized skills and knowledge, who assisted in evaluating the Company's resource valuation metric derived from the CGU resources cash flows by comparing to publicly available market data and valuation metrics for comparable entities.

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 7 to the consolidated financial statements, the Company recorded depletion expense related to oil and gas properties of $1,039.8 million for the year ended December 31, 2023. The estimation of area reserves requires the expertise of independent qualified reserve evaluators who take into consideration assumptions related to forecasted production volumes, royalty obligations, operating and capital costs and commodity prices (collectively "area reserve report assumptions"). The Company engages independent qualified reserve 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 area reserve report assumptions 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 area reserve report 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 by depletable area
- the Company's determination of area reserve report 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 qualified reserve evaluators engaged by the Company. We evaluated the methodology used by the independent qualified reserve evaluators to estimate area reserves for compliance with the applicable regulatory standards. We compared the current year actual production volumes, royalty obligations, operating and capital costs to those estimates used in the prior year estimate of proved reserves 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, royalty obligations, 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 28, 2024

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, 2023, 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, 2023, 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 at December 31, 2023 and 2022, 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 28, 2024 expressed an unqualified opinion on those consolidated financial statements.

The Company acquired Ranger Oil Corporation during 2023, and management excluded from its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2023, Ranger Oil Corporation's internal control over financial reporting associated with total assets of $3.5 billion and total revenues, net of royalties, of $691.9 million included in the consolidated financial statements of the Company as of and for the year ended December 31, 2023. Our audit of internal control over financial reporting of the Company also excluded an evaluation of the internal control over financial reporting of Ranger Oil Corporation.

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 28, 2024

Baytex Energy Corp.
Consolidated Statements of Financial Position

(thousands of Canadian dollars)

As at	Notes	December 31, 2023	December 31, 2022
ASSETS			
Current assets			
Cash		**$ 55,815**	$ 5,464
Trade receivables	18	**339,405**	222,108
Prepaids and other assets		**21,530**	6,377
Financial derivatives	18	**23,274**	10,105
		440,024	244,054
Non-current assets			
Exploration and evaluation assets	6	**90,919**	168,684
Oil and gas properties	7	**6,619,033**	4,620,766
Other plant and equipment		**7,936**	6,568
Lease assets		**28,145**	6,453
Prepaids and other assets	15	**61,729**	—
Deferred income tax asset	15	**213,145**	57,244
		$ 7,460,931	$ 5,103,769
LIABILITIES			
Current liabilities			
Trade payables		**$ 477,295**	$ 227,332
Share-based compensation liability	12	**28,508**	44,863
Dividends payable	11,18	**18,381**	—
Lease obligations		**13,391**	3,521
Asset retirement obligations	10	**20,448**	12,813
		558,023	288,529
Non-current liabilities			
Other long-term liabilities		**19,147**	—
Share-based compensation liability	12	**7,224**	9,209
Credit facilities	8	**848,749**	383,031
Long-term notes	9	**1,562,361**	547,598
Lease obligations		**16,056**	3,017
Asset retirement obligations	10	**602,951**	576,110
Deferred income tax liability	15	**21,333**	265,858
		3,635,844	2,073,352
SHAREHOLDERS' EQUITY			
Shareholders' capital	11	**6,527,289**	5,499,664
Contributed surplus		**193,077**	89,879
Accumulated other comprehensive income		**690,917**	756,195
Deficit		**(3,586,196)**	(3,315,321)
		3,825,087	3,030,417
		$ 7,460,931	$ 5,103,769

Subsequent events (note 11 and note 18) and Commitments (note 20)

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	2023	2022
Revenue, net of royalties			
Petroleum and natural gas sales	14	**$ 3,382,621**	$ 2,889,045
Royalties		**(669,792)**	(562,964)
		2,712,829	2,326,081
Expenses			
Operating		**570,839**	422,666
Transportation		**89,306**	48,561
Blending and other		**224,802**	189,454
General and administrative		**69,789**	50,270
Transaction costs	4	**49,045**	—
Exploration and evaluation	6	**8,896**	30,239
Depletion and depreciation		**1,047,904**	587,050
Impairment loss (reversal)	6, 7	**833,662**	(267,744)
Share-based compensation	12	**37,699**	29,056
Financing and interest	16	**192,173**	104,817
Financial derivatives (gain) loss	18	**(24,695)**	199,010
Foreign exchange (gain) loss	17	**(10,848)**	43,441
Loss (gain) on dispositions		**141,295**	(4,898)
Other (income) expense		**(456)**	3,244
		3,229,411	1,435,166
Net (loss) income before income taxes		**(516,582)**	890,915
Income tax (recovery) expense	15		
Current income tax expense		**14,403**	3,594
Deferred income tax (recovery) expense		**(297,629)**	31,716
		(283,226)	35,310
Net (loss) income		**$ (233,356)**	$ 855,605
Other comprehensive (loss) income			
Foreign currency translation adjustment		**(65,278)**	124,092
Comprehensive (loss) income		**$ (298,634)**	$ 979,697
Net (loss) income per common share	13		
Basic		**$ (0.33)**	$ 1.53
Diluted		**$ (0.33)**	$ 1.52
Weighted average common shares	13		
Basic		**704,896**	557,986
Diluted		**704,896**	563,835

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, 2021		$ 5,736,593	$ 13,559	$ 632,103	$ (4,170,926)	**$ 2,211,329**
Vesting of share awards	11	8,501	(8,501)	—	—	**—**
Share-based compensation	12	—	3,159	—	—	**3,159**
Repurchase of common shares for cancellation		(245,430)	86,453	—	—	**(158,977)**
Transfers for liability-classified awards		—	(4,791)	—	—	**(4,791)**
Comprehensive income		—	—	124,092	855,605	**979,697**
Balance at December 31, 2022		$ 5,499,664	$ 89,879	$ 756,195	$ (3,315,321)	**$ 3,030,417**
Issued on corporate acquisition	4	1,326,435	21,316	—	—	**1,347,751**
Vesting of share awards	11	26,229	(37,462)	—	—	**(11,233)**
Share-based compensation	12	—	16,237	—	—	**16,237**
Repurchase of common shares for cancellation	11	(325,039)	103,107	—	—	**(221,932)**
Dividends declared	11	—	—	—	(37,519)	**(37,519)**
Comprehensive loss		—	—	(65,278)	(233,356)	**(298,634)**
Balance at December 31, 2023		$ 6,527,289	$ 193,077	$ 690,917	$ (3,586,196)	**$ 3,825,087**

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	2023	2022
CASH PROVIDED BY (USED IN):			
Operating activities			
Net (loss) income		**$ (233,356)**	$ 855,605
Adjustments for:			
Non-cash share-based compensation	12	**16,237**	3,159
Unrealized foreign exchange (gain) loss	17	**(14,300)**	45,073
Exploration and evaluation	6	**8,896**	30,239
Depletion and depreciation		**1,047,904**	587,050
Impairment loss (reversal)	6, 7	**833,662**	(267,744)
Non-cash financing and accretion	16	**32,350**	24,431
Non-cash other income	10	**(1,271)**	(4,009)
Unrealized financial derivatives loss (gain)	18	**11,517**	(135,471)
Cash premiums on derivatives		**(2,263)**	—
Loss (gain) on dispositions		**141,295**	(4,898)
Deferred income tax (recovery) expense	15	**(297,629)**	31,716
Asset retirement obligations settled	10	**(26,416)**	(18,351)
Change in non-cash working capital	19	**(220,895)**	26,072
Cash flows from operating activities		**1,295,731**	1,172,872
Financing activities			
Increase (decrease) in credit facilities	8	**477,387**	(136,980)
Decrease in acquired credit facilities	4	**(373,608)**	—
Debt issuance costs		**(40,424)**	(2,138)
Payments on lease obligations		**(11,527)**	(3,732)
Net proceeds from issuance of long-term notes	9	**1,046,197**	—
Redemption of long-term notes	9	**—**	(376,589)
Redemption of acquired long-term notes	4	**(569,256)**	—
Repurchase of common shares	11	**(221,932)**	(158,977)
Dividends declared	11	**(37,519)**	—
Change in non-cash working capital	19	**(3,068)**	—
Cash flows from (used in) financing activities		**266,250**	(678,416)
Investing activities			
Additions to exploration and evaluation assets	6	**—**	(6,359)
Additions to oil and gas properties	7	**(1,012,787)**	(515,183)
Additions to other plant and equipment		**(4,416)**	(1,148)
Corporate acquisition, net of cash acquired	4	**(662,579)**	—
Property acquisitions		**(38,914)**	(1,352)
Proceeds from dispositions		**160,256**	25,649
Change in non-cash working capital	19	**46,810**	9,401
Cash flows used in investing activities		**(1,511,630)**	(488,992)
Change in cash		**50,351**	5,464
Cash, beginning of year		**5,464**	—
Cash, end of year		**$ 55,815**	$ 5,464
Supplementary information			
Interest paid		**$ 153,224**	$ 84,225
Income taxes paid		**$ 3,603**	$ 2,303

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 and the New York Stock Exchange under the symbol BTE. The Company’s head and principal office is located at 2800, 520 – 3rd Avenue S.W., Calgary, Alberta, T2P 0R3, and its registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

2. BASIS OF PREPARATION

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 material 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 28, 2024.

The consolidated financial statements have been prepared on a historical cost basis, with the exception of certain fair value measurements noted in the material 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.

Certain prior year amounts have been reclassified to conform to current year presentation, including prepaids and other assets and share-based compensation liability.

Measurement Uncertainty and Judgments

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.

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 various regulatory and legislative requirements, to the Company at the time of financial statement preparation. Actual results could be materially different from those estimates as the effect of future events cannot be determined with certainty. Revisions to estimates are recognized prospectively. 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 recoverable 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 qualified reserves evaluators and represent the estimated recoverable quantities of oil, natural gas and NGL reserves and the related 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 reserves and the related cash flows are based on a number of factors and assumptions. Changes to estimates and assumptions such as forecasted commodity prices, production volumes, capital and operating costs and royalty obligations could have a significant impact on reported reserves. Other estimates include ultimate reserve recovery, marketability of oil and natural gas and other geological, economic and technical factors. Changes in the Company's reserves estimates can have a significant impact on the calculation of depletion, the recoverability of deferred income tax assets and in the determination of recoverable value estimates for non-financial assets.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting when the assets acquired meet the definition of a business in accordance with IFRS. The determination of the fair value assigned to assets acquired and liabilities assumed requires management to make assumptions and estimates. These assumptions or estimates used in determining the fair value of assets acquired and liabilities assumed could impact the amounts assigned to assets, liabilities and goodwill. The determination of the acquisition-date fair value measurement of oil and gas properties acquired represents the largest fair value estimate which is derived from the present value of expected cash flows associated with estimated acquired proved and probable oil and gas reserves prepared by an independent qualified reserve evaluator using assumptions as outlined under "reserves", on an after-tax basis and applying a discount rate. Assumptions used to arrive at the fair value of oil and gas properties are further verified by way of market comparisons and third party sources.

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 inflows that are largely independent of the cash inflows 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. These indicators can be internal such as changes in estimated proved and probable oil and gas reserves ("CGU reserves") and internally estimated oil and gas resources, or external such as market conditions impacting discount rates or market capitalization. The assessment for each CGU considers significant changes in the forecasted cash flows including reservoir performance, the number of development locations and timing of development, forecasted commodity prices, production volumes, capital and operating costs and royalty obligations.

Measurement of Recoverable Amounts

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 and probable oil and gas reserves and the discount rate used to present value future cash flows. Any changes to these estimates and assumptions could impact the calculation of the recoverable amount and the carrying value of assets.

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 risk-free discount rates and inflation rates. The Company uses risk-free discount 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.

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. Income tax filings are subject to audit and re-assessment and changes in facts, circumstances and interpretations of the applicable legislative requirements may result in a material change to the Company's provision for income taxes.

Environmental Reporting Regulations

Environmental reporting for public enterprises continues to evolve and the Company 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. Baytex continues to monitor developments on these reporting requirements and has not yet quantified the cost to comply with these regulations.

3. MATERIAL 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 jointly owned assets. The consolidated financial statements include the Company's proportionate share of the assets, liabilities, revenues and expenses generated by jointly owned assets.

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 and it is physically transferred to the customer at the agreed upon delivery point.

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

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

Exploration and Evaluation ("E&E") Assets

Once the legal right to explore has been acquired, costs directly associated with an exploration program are capitalized as E&E assets 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 expenditures are costs incurred in an area where technical feasibility and commercial viability has not yet been determined. The technical feasibility and commercial viability is dependent on whether extracting petroleum and natural gas resources is demonstrable. If the asset is determined not to be technically feasible or commercially viable the accumulated E&E assets 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 demonstrating the ability to extract mineral resources 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 and complete wells for production, 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

The costs associated with oil and gas properties are depleted on a unit-of-production basis by depletable area over proved and probable reserves once commercial production has commenced. Forecasted capital costs required to bring proved and probable 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 oil and gas properties and E&E assets at a CGU level for indicators of impairment and impairment reversal at the end of each reporting period. E&E assets are also assessed for impairment upon transfer to oil and gas properties. The recoverable amount of the asset is estimated if indicators of impairment or impairment reversal exist.

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 forecasted CGU production volumes, royalty obligations, operating costs, capital costs, commodity prices, taxes, along with inflation and discount rates used to estimate present value. FVLCD is the amount that would be obtained from the sale of an asset or CGU in an arm's length transaction. In determining FVLCD, recent comparable 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 based on the Company’s weighted average cost of capital adjusted for risks specific to the CGU.

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 the individual assets in the CGU on a pro-rata basis.

Impairments may be reversed for all CGUs and individual assets 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 CGU’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.

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 financing and interest expense in net 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. The Company's U.S. operations are conducted in USD. Management judgement is required in the designation of a subsidiary's functional currency.

The financial statements of each entity are translated into Canadian dollars during the preparation of the Company's consolidated financial statements. Refer to the *Consolidation* section of Note 3 for a list of the Company's entities. 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 two categories: measured at amortized cost or fair value through profit or loss (“FVTPL”).

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

Financial Instrument	**Classification**
Cash	Amortized cost
Trade receivables	Amortized cost
Financial derivatives	Fair value through profit or loss
Trade payables	Amortized cost
Dividends payable	Amortized cost
Credit facilities	Amortized cost
Long-term notes	Amortized cost

Debt issuance costs related to the amendment of the Company's 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 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. 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 accounts for its physical delivery sales contracts as executory contracts. These contracts are entered into and held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements. As such, these contracts are not considered to be derivative financial instruments and are not 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.

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 upheld. The asset or liability is measured based on an assessment of probable 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 deductible temporary differences 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 or increased to the extent that it is no longer probable or becomes 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.

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.

New Accounting Standards Adopted

In 2023, Baytex adopted amendments to IAS 12 *Income Taxes* regarding relief from deferred tax accounting for top-up tax under Pillar Two. Pillar Two refers to a minimum 15% tax rate on the income generated by multinational corporations in the jurisdictions in which they operate. Baytex applies the exception to recognizing and disclosing information about deferred taxes related to Pillar Two income taxes, as provided in the amendments to IAS 12 issued in May 2023. This amendment did not have a material impact on our consolidated financial statements.

Baytex has adopted amendments to IAS 1 *Presentation of Financial Statements* regarding the disclosure of material accounting policies, effective January 1, 2023. This amendment was disclosure related and did not impact the Company's accounting policies.

Future Accounting Pronouncements

Effective January 1, 2024, Baytex plans to adopt amendments to IAS 1 *Presentation of Financial Statements* which was issued by the IASB in January 2020. The amendments further clarify the requirements for the presentation of liabilities as current or non-current in the consolidated statements of financial position.

In October 2022, the IASB issued *Non-current Liabilities with Covenants* which amended IAS 1 *Presentation of Financial Statements*. The amendments specify the classification and disclosure of a liability with covenants and is effective January 1, 2024.

These amendments are not expected to have a material impact on our consolidated financial statements.

4. BUSINESS COMBINATION

On June 20, 2023, Baytex closed the acquisition of Ranger Oil Corporation (“Ranger”), a publicly traded oil and gas exploration and production company with operations in the Eagle Ford. Baytex acquired all of the issued and outstanding common shares of Ranger and is treated as the acquirer for accounting purposes. The acquisition increases Baytex's Eagle Ford scale and provides an operating platform to effectively allocate capital across the Western Canadian Sedimentary Basin and the Eagle Ford.

The acquisition was accounted for as a business combination with the net assets and liabilities recorded at fair value at the acquisition date. The total consideration of US$1.6 billion ($2.1 billion) consisted of $732.8 million of cash consideration and 311.4 million Baytex common shares valued at approximately $1.3 billion (based on the closing price of Baytex’s common shares of $4.26 per share on the Toronto Stock Exchange on June 20, 2023). Under the terms of the agreement, Ranger shareholders received 7.49 Baytex shares plus US$13.31 cash for each share of Ranger common stock.

The fair value of oil and gas properties acquired is primarily based on estimated cash flows associated with proved and probable oil and gas reserves acquired and the discount rate. Factors that impact these reserves cash flows include forecasted production volumes, royalty obligations, operating and capital costs, taxes and commodity prices. The estimation of reserves cash flows involves the expertise of the independent qualified reserve evaluators. Any changes to these estimates and assumptions could impact the calculation of the recoverable amount and the carrying value of assets. The fair value of the acquired oil and gas properties were determined using a discount rate of 12.2%.

Asset retirement obligations were determined using internal estimates of the timing and estimated costs associated with the abandonment and reclamation of the wells and facilities acquired using a market rate of interest of 9.0%.

The total consideration paid and estimates of the fair value of the assets and liabilities acquired as at the date of the acquisition are set forth in the table below. The preliminary purchase price equation is based on Management's best estimate of the assets acquired and liabilities assumed. Adjustments to these initial estimates may be required upon finalizing the value of net assets acquired.

		USD		CAD [1]
Consideration				
Cash	$	553,150	$	732,840
Common shares issued		1,001,196		1,326,435
Share based compensation [2]		20,107		26,638
Total consideration	**$**	**1,574,453**	**$**	**2,085,913**
Fair value of net assets acquired				
Oil and gas properties [3]	$	2,337,173	$	3,096,404
Working capital deficiency excluding bank debt and financial derivatives [3][4]		(120,565)		(159,731)
Financial derivatives		17,030		22,562
Lease assets		15,708		20,811
Lease obligations		(15,708)		(20,811)
Credit facilities		(282,000)		(373,608)
Long-term notes		(429,676)		(569,256)
Asset retirement obligations		(23,632)		(31,310)
Deferred income tax asset [3]		76,123		100,852
Net assets acquired	**$**	**1,574,453**	**$**	**2,085,913**

(1) Exchange rate used to translate the U.S. denominated values above is the rate as at the closing date being CAD/USD 1.32485.

(2) Following closing of the transaction, holders of awards outstanding under Ranger's share based compensation plans are entitled to Baytex common shares rather than Ranger common shares with adjustment to the quantity outstanding based on the exchange ratio for Ranger shares. The fair value of share awards allocated to consideration was based on the service period that had occurred prior to the acquisition date while the remaining fair value of the share awards assumed by Baytex will be recognized over the remaining future service periods (note 12). Included in this balance is $21.3 million (US$16.1 million) of awards that were fully vested at close of the Ranger acquisition and $5.3 million (US$4.0 million) of cash-based awards included in share-based compensation liability.

(3) Adjustments were recorded to the preliminary fair value to reflect circumstances that existed as at the acquisition date. These adjustments relate to an update in operating results which increased our working capital deficiency by $16.4 million (US$12.4 million) with an offset to oil and gas properties and an increase in the deferred income tax asset of $1.6 million (US$1.2 million) as a result.

(4) Includes $70.3 million (US$53.0 million) of cash. Trade receivables acquired is net of a provision for expected credit losses of approximately $0.3 million.

The cash portion of the transaction was funded with Baytex's expanded credit facility which increased to US$1.1 billion at close of the transaction, US$150 million from a two-year term loan facility, and the net proceeds from the issuance of US$800 million senior unsecured notes due 2030. Baytex closed the US$800 million, senior unsecured note offering on April 27, 2023 and the net proceeds were released from escrow on June 20, 2023.

These consolidated financial statements include the results of operations of Ranger for the period following closing of the transaction on June 20, 2023. For the year ended December 31, 2023, the acquisition contributed revenues and net income before income taxes of $939.4 million and $165.1 million, respectively. Had the acquisition occurred on January 1, 2023, revenues and net income before income taxes would have increased by approximately $1.7 billion and $366.7 million, respectively, for the year ended December 31, 2023. This pro-forma information is not necessarily indicative of the results of operations that would have resulted had the acquisition been reflected on the dates indicated, or that may be obtained in the future.

During the year ended December 31, 2023, Baytex incurred transaction costs of $49.0 million. Transaction costs include consulting, advisory fees, legal fees, tax fees and other professional fees of $41.7 million, as well as post-combination employee-related costs of $7.3 million.

5. SEGMENTED FINANCIAL INFORMATION

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

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

	Canada		U.S.		Corporate		Consolidated	
Years Ended December 31	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 1,729,021**	$ 1,926,561	**$ 1,653,600**	$ 962,484	**$ —**	$ —	**$ 3,382,621**	$ 2,889,045
Royalties	**(213,148)**	(277,428)	**(456,644)**	(285,536)	**—**	—	**(669,792)**	(562,964)
	1,515,873	1,649,133	**1,196,956**	676,948	**—**	—	**2,712,829**	2,326,081
Expenses								
Operating	**368,605**	327,894	**202,234**	94,772	**—**	—	**570,839**	422,666
Transportation	**64,325**	48,561	**24,981**	—	**—**	—	**89,306**	48,561
Blending and other	**224,802**	189,454	**—**	—	**—**	—	**224,802**	189,454
General and administrative	**—**	—	**—**	—	**69,789**	50,270	**69,789**	50,270
Transaction costs	**—**	—	**—**	—	**49,045**	—	**49,045**	—
Exploration and evaluation	**8,896**	30,239	**—**	—	**—**	—	**8,896**	30,239
Depletion and depreciation	**484,232**	409,286	**555,548**	171,747	**8,124**	6,017	**1,047,904**	587,050
Impairment loss (reversal)	**184,000**	(267,744)	**649,662**	—	**—**	—	**833,662**	(267,744)
Share-based compensation	**—**	—	**—**	—	**37,699**	29,056	**37,699**	29,056
Financing and interest	**—**	—	**—**	—	**192,173**	104,817	**192,173**	104,817
Financial derivatives (gain) loss	**—**	—	**—**	—	**(24,695)**	199,010	**(24,695)**	199,010
Foreign exchange (gain) loss	**—**	—	**—**	—	**(10,848)**	43,441	**(10,848)**	43,441
Loss (gain) on dispositions	**141,295**	(4,898)	**—**	—	**—**	—	**141,295**	(4,898)
Other (income) expense	**(1,271)**	(4,009)	**—**	—	**815**	7,253	**(456)**	3,244
	1,474,884	728,783	**1,432,425**	266,519	**322,102**	439,864	**3,229,411**	1,435,166
Net income (loss) before income taxes	**40,989**	920,350	**(235,469)**	410,429	**(322,102)**	(439,864)	**(516,582)**	890,915
Income tax (recovery) expense								
Current income tax expense							**14,403**	3,594
Deferred income tax (recovery) expense							**(297,629)**	31,716
							(283,226)	35,310
Net income (loss)	**$ 40,989**	$ 920,350	**$ (235,469)**	$ 410,429	**$ (322,102)**	$ (439,864)	**$ (233,356)**	$ 855,605
Additions to exploration and evaluation assets	**—**	6,359	**—**	—	**—**	—	**—**	6,359
Additions to oil and gas properties	**463,198**	374,443	**549,589**	140,740	**—**	—	**1,012,787**	515,183
Corporate acquisition, net of cash acquired	**—**	—	**662,579**	—	**—**	—	**662,579**	—
Property acquisitions	**20,023**	1,352	**18,891**	—	**—**	—	**38,914**	1,352
Proceeds from dispositions	**(160,256)**	(25,649)	**—**	—	**—**	—	**(160,256)**	(25,649)

As at	**December 31, 2023**	December 31, 2022
Canadian assets	**$ 2,289,083**	$ 2,779,596
U.S. assets	**5,112,493**	2,301,047
Corporate assets	**59,355**	23,126
Total consolidated assets	**$ 7,460,931**	$ 5,103,769

6. EXPLORATION AND EVALUATION ASSETS

	December 31, 2023	December 31, 2022
Balance, beginning of year	**$ 168,684**	$ 172,824
Capital expenditures	**—**	6,359
Property acquisitions	**18,486**	301
Divestitures	**(2,965)**	(498)
Property swaps	**1,000**	385
Impairment reversal	**—**	22,503
Exploration and evaluation expense	**(8,896)**	(30,239)
Transfers to oil and gas properties (note 7)	**(83,530)**	(8,496)
Foreign currency translation	**(1,860)**	5,545
Balance, end of year	**$ 90,919**	$ 168,684

At December 31, 2023, there were no indicators of impairment or impairment reversal for exploration and evaluation assets in any of the Company's CGUs.

At December 31, 2022, the Company identified indicators of impairment reversal for the exploration and evaluation assets within the Peace River CGU due to an increase in land sale values. The recoverable amount for the Peace River CGU exceeded its carrying value and an impairment reversal of $22.5 million was recorded at December 31, 2022. The recoverable amount was based on the CGUs FVLCD and was estimated with reference to arm's length transactions in comparable locations.

7. OIL AND GAS PROPERTIES

	Cost	Accumulated depletion	Net book value
Balance, December 31, 2021	**$ 11,633,517**	**$ (7,169,146)**	**$ 4,464,371**
Capital expenditures	515,183	—	515,183
Property acquisitions	1,173	—	1,173
Transfers from exploration and evaluation assets (note 6)	8,496	—	8,496
Change in asset retirement obligations (note 10)	(147,020)	—	(147,020)
Divestitures	(265,166)	241,892	(23,274)
Impairment reversal	—	245,241	245,241
Foreign currency translation	296,033	(158,404)	137,629
Depletion	—	(581,033)	(581,033)
Balance, December 31, 2022	**$ 12,042,216**	**$ (7,421,450)**	**$ 4,620,766**
Capital expenditures	1,012,787	—	1,012,787
Corporate acquisition (note 4)	3,096,404	—	3,096,404
Property acquisitions	20,263	—	20,263
Transfers from exploration and evaluation assets (note 6)	83,530	—	83,530
Transfers from lease assets	7,611	—	7,611
Change in asset retirement obligations (note 10)	54,166	—	54,166
Divestitures	(660,920)	317,651	(343,269)
Property swaps	(2,975)	3,756	781
Impairment loss	—	(833,662)	(833,662)
Foreign currency translation	(127,065)	66,501	(60,564)
Depletion	—	(1,039,780)	(1,039,780)
Balance, December 31, 2023	**$ 15,526,017**	**$ (8,906,984)**	**$ 6,619,033**

At December 31, 2023, there were no indicators of impairment or impairment reversal for oil and gas properties in five CGUs and no impairment testing was required, including for the Eagle Ford Operated CGU which includes the assets acquired from Ranger (note 4).

2023 Impairment

At December 31, 2023, the Company identified indicators of impairment for oil and gas properties in two CGUs due to changes in reserves volumes and a loss recorded on a disposition of an asset within an existing CGU. The recoverable amounts for the two CGUs were not sufficient to support their carrying values which resulted in an impairment of $833.7 million recorded at December 31, 2023. The recoverable amount for each CGU is based on estimated cash flows associated with proved and probable oil and gas reserves from an independent reserve report prepared as at December 31, 2023 utilizing a discount rate based on Baytex's corporate weighted average cost of capital adjusted for asset specific factors. The after-tax discount rates applied to the cash flows were between 12% and 14%.

At December 31, 2023, the recoverable amounts of the two CGUs were calculated using the following benchmark reference prices for the years 2024 to 2033 adjusted for commodity differentials specific to the CGU. The prices and costs subsequent to 2033 have been adjusted for inflation at an annual rate of 2.0%.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
WTI crude oil (US$/bbl)	73.67	74.98	76.14	77.66	79.22	80.80	82.42	84.06	85.74	87.46
LLS crude oil (US$/bbl)	76.49	77.80	78.95	80.35	81.95	83.59	85.27	86.97	88.71	90.48
Edmonton par oil ($/bbl)	92.91	95.04	96.07	97.99	99.95	101.94	103.98	106.06	108.18	110.35
NYMEX Henry Hub gas (US$/mmbtu)	2.75	3.64	4.02	4.10	4.18	4.27	4.35	4.44	4.53	4.62
AECO gas ($/mmbtu)	2.20	3.37	4.05	4.13	4.21	4.30	4.38	4.47	4.56	4.65
Exchange rate (CAD/USD)	0.75	0.75	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76

The following table summarizes the recoverable amount and impairment for each of the two CGUs at December 31, 2023 and demonstrates the sensitivity of the impairment to reasonably possible changes in key assumptions inherent in the calculation.

	Recoverable amount	Impairment loss	Change in discount rate of 1%	Change in oil price of $2.50/bbl	Change in gas price of $0.25/mcf
Viking CGU	$ 606,290	$ 184,000	$ 26,500	$ 53,000	$ 3,500
Eagle Ford Non-op CGU [(1)]	1,429,658	649,662	71,300	107,600	25,700

(1) There were no indicators of impairment identified for the Eagle Ford Operated CGU which includes the assets acquired from Ranger (note 4).

2022 Impairment Reversal

At December 31, 2022, indicators of impairment reversal were identified for oil and gas properties in five CGUs due to the increase in forecasted commodity prices in addition to changes in reserves volumes. The recoverable amount for three CGUs exceeded their carrying values which resulted in an impairment reversal of $245.2 million recorded at December 31, 2022. The recoverable amount for each CGU is based on estimated cash flows associated with proved and probable oil and gas reserves from an independent reserve report prepared as at December 31, 2022 with a discount rate based on Baytex's corporate weighted average cost of capital adjusted for asset specific factors. The after-tax discount rates applied to the cash flows were between 12% and 23%.

The following table summarizes the recoverable amount and impairment reversal for each of the five CGUs at December 31, 2022 and demonstrates the sensitivity of the impairment reversal to reasonably possible changes in key assumptions inherent in the calculation.

	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 [(1)]	$ 119,031	$ 23,707	$ —	$ —	—
Peace River CGU [(1)]	676,939	140,534	—	—	—
Lloydminster CGU	449,250	—	11,500	53,000	—
Viking CGU	1,322,193	81,000	39,500	78,000	4,000
Eagle Ford Non-op CGU	2,102,646	—	95,800	131,100	28,500

(1) The impairment reversals for the Conventional and Peace River CGUs were limited to the total accumulated impairments less subsequent depletion of $23.7 million and $140.5 million, respectively. As a result, changes in the key assumptions presented in the table above have no impact on the amount of the impairment reversal as at December 31, 2022.

8. CREDIT FACILITIES

	December 31, 2023	December 31, 2022
Credit facilities - U.S. dollar denominated[1]	**$ 311,980**	$ 30,394
Credit facilities - Canadian dollar denominated	**552,756**	355,000
Credit facilities - principal [2]	**$ 864,736**	$ 385,394
Unamortized debt issuance costs	**(15,987)**	(2,363)
Credit facilities	**$ 848,749**	$ 383,031

(1) U.S. dollar denominated credit facilities balance was US$236.3 million as at December 31, 2023 (December 31, 2022 - US$22.5 million).
(2) The increase in the principal amount of the credit facilities outstanding from December 31, 2022 to December 31, 2023 is the result of net draws of $ 477.4 million along with an increase in the reported amount of U.S. denominated debt of $2.0 million due to foreign exchange.

At December 31, 2023, Baytex had US$1.1 billion ($1.5 billion) of revolving credit facilities (the "Credit Facilities"). On June 20, 2023, in connection with the acquisition of Ranger, Baytex amended its Credit Facilities to increase the committed amount to $1.1 billion ($1.5 billion) (previously US$850 million in aggregate as of April 1, 2022). The maturity date of the Credit Facilities is April 1, 2026. Baytex also entered into a secured two-year term loan of US$150 million that was repaid and cancelled in August 2023.

The Credit Facilities are secured and are comprised of a US$50 million operating loan and a US$750 million syndicated revolving loan for Baytex and a US$45 million operating loan and a US$255 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc. The amended Credit Facilities contain an additional financial covenant of a maximum Total Debt to Bank EBITDA ratio of 4.0:1.0 and increased the Interest Coverage minimum ratio to 3.5:1.0 (from 2.0:1.0).

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 by Baytex. Advances under the Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank's prime lending rate, bankers' acceptance discount rates or secured overnight financing rates ("SOFR"), plus applicable margins.

The weighted average interest rate on the Credit Facilities was7.6% for the year ended December 31, 2023 (3.6% for the year ended December 31, 2022).

The following table summarizes the financial covenants applicable to the Credit Facilities and the Company's compliance therewith at December 31, 2023.

Covenant Description	**Position as at December 31, 2023**	**Covenant**
Senior Secured Debt [1] to Bank EBITDA [2] (Maximum Ratio)	**0.4:1.0**	3.5:1.0
Interest Coverage [3] (Minimum Ratio)	**11.3:1.0**	3.5:1.0
Total Debt [4] to Bank EBITDA [2] (Maximum Ratio)	**1.1:1.0**	4.0:1.0

(1) "Senior Secured Debt" is calculated in accordance with the credit facility agreement and is defined as the principal amount of the Credit Facilities and other secured obligations identified in the credit facility agreement. As at December 31, 2023, the Company's Senior Secured Debt totaled $864.7 million.
(2) "Bank EBITDA" is calculated based on terms and definitions set out in the credit facility 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, 2023 was $2.2 billion.
(3) "Interest coverage" is calculated in accordance with the credit facility 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 including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Financing and interest expenses for the year ended December 31, 2023 was $195.2 million.
(4) "Total Debt" is calculated in accordance with the credit facility agreement and is defined as all obligations, liabilities, and indebtedness of Baytex excluding trade payables, share-based compensation liability, dividends payable, asset retirement obligations, leases, deferred income tax liabilities, other long-term liabilities and financial derivative liabilities. As at December 31, 2023, the Company's Total Debt totaled $2.5 billion of principal amounts outstanding.

At December 31, 2023, Baytex had $5.6 million of outstanding letters of credit, $4.7 million of which is under a $20 million uncommitted unsecured demand revolving letter of credit facility (December 31, 2022 - $15.7 million outstanding). Letters of credit under this facility are guaranteed by Export Development Canada and do not use capacity available under the Credit Facilities.

9. LONG-TERM NOTES

	December 31, 2023	December 31, 2022
8.75% notes due April 1, 2027 [1]	**$ 541,114**	$ 554,597
8.50% notes due April 30, 2030 [2]	**1,056,361**	—
Total long-term notes - principal [3]	**$ 1,597,475**	$ 554,597
Unamortized debt issuance costs	**(35,114)**	(6,999)
Total long-term notes - net of unamortized debt issuance costs	**$ 1,562,361**	$ 547,598

(1) The U.S. dollar denominated principal outstanding of the 8.75% notes was US$409.8 million at December 31, 2023 (December 31, 2022 - US$409.8 million).
(2) The U.S. dollar denominated principal outstanding of the 8.50% notes was US$800.0 million at December 31, 2023 (December 31, 2022 - nil).
(3) The increase in the principal amount of long-term notes outstanding from December 31, 2022 to December 31, 2023 is the result of the issuance of the 8.50% notes for $1.1 billion and includes changes in the reported amount of U.S. denominated debt of $17.0 million due to changes in the CAD/USD exchange rate used to translate the U.S. denominated amount of long-term notes outstanding.

On April 27, 2023, we issued US$800 million aggregate principal amount of senior unsecured notes due April 30, 2030 bearing interest at a rate of 8.50% per annum semi-annually (the "8.50% Senior Notes"). The 8.50% Senior Notes were issued at 98.709% of par and are redeemable at our option, in whole or in part, at specified redemption prices after April 30, 2026 and will be redeemable at par from April 30, 2028 to maturity. Net proceeds of $1.0 billion reflects $13.7 million for the original issue discount and Baytex also incurred transaction costs of $18.5 million in conjunction with the issuance.

The long-term notes do not contain any significant financial maintenance covenants but do contain standard commercial covenants for debt incurrence and restricted payments.

10. ASSET RETIREMENT OBLIGATIONS

	December 31, 2023	December 31, 2022
Balance, beginning of year	**$ 588,923**	$ 743,683
Liabilities incurred [1]	**24,185**	19,942
Liabilities settled	**(26,416)**	(18,351)
Liabilities assumed from corporate acquisition (note 4)	**31,310**	—
Liabilities acquired from property acquisitions	**11**	950
Liabilities divested	**(43,153)**	(3,464)
Property swaps	**76**	—
Accretion (note 16)	**20,406**	15,683
Government grants [2]	**(1,271)**	(4,009)
Change in estimate [1]	**17,067**	6,124
Changes in discount rates and inflation rates [1][3]	**12,914**	(173,086)
Foreign currency translation	**(653)**	1,451
Balance, end of year	**$ 623,399**	$ 588,923
Less current portion of asset retirement obligations	**20,448**	12,813
Non-current portion of asset retirement obligations	**$ 602,951**	$ 576,110

(1) The total of these items reflects the total change in asset retirement obligations of $54.2 million per Note 7 - Oil and Gas Properties ($147 million decrease in 2022).
(2) During 2023, Baytex recognized $1.3 million of non-cash other income and a reduction in asset retirement obligations related to government grants provided by the Government of Alberta and the Government of Saskatchewan ($4.0 million in 2022).
(3) The discount and inflation rates used to calculate the liability for our Canadian operations at December 31, 2023 were 3.0% and 1.6% respectively (December 31, 2022 - 3.3% and 2.1%). The discount and inflation rates used to calculate the liability for our U.S. operations at December 31, 2023 were 4.0% and 2.1%, respectively (December 31, 2022 - 3.3% and 2.1%). The changes in discount rates also includes the remeasurement of the liability acquired from Ranger from a market rate of interest on the date of acquisition to a risk-free rate at period end.

At December 31, 2023, the undiscounted, uninflated amount of estimated cash flows required to settle the asset retirement obligations is $795.5 million (December 31, 2022 - $724.8 million). The discounted amount of estimated cash flow required to settle the asset retirement obligations at December 31, 2023 is $623.4 million (December 31, 2022 - $588.9 million). This was calculated using an estimated inflation rate of 1.6% and 2.1% for Canadian and U.S. operations, respectively (December 31, 2022 - 2.1%) and a risk-free discount rate of 3.0% and 4.0% for Canadian and U.S. operations, respectively (December 31, 2022 - 3.3%). These costs are expected to be incurred over the next 60 years.

11. 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, 2023, 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, 2021	**564,213**	**$ 5,736,593**
Vesting of share awards	5,035	8,501
Common shares repurchased and cancelled	(24,318)	(245,430)
Balance, December 31, 2022	**544,930**	**$ 5,499,664**
Issued on corporate acquisition (note 4)	311,370	1,326,435
Vesting of share awards	5,892	26,229
Common shares repurchased and cancelled	(40,511)	(325,039)
Balance, December 31, 2023	**821,681**	**$ 6,527,289**

Normal Course Issuer Bid ("NCIB") Share Repurchases

On June 23, 2023, Baytex announced the acceptance from the Toronto Stock Exchange ("TSX") for renewal of the NCIB under which Baytex is permitted to purchase for cancellation 68.4 million common shares over the 12-month period commencing June 29, 2023. The number of shares authorized for repurchase represents 10% of the Company's 856.9 million common shares outstanding as at June 21, 2023.

Purchases are made on the open market at prices prevailing at the time of the transaction. During the year ended December 31, 2023, Baytex repurchased and cancelled 40.5 million common shares at an average price of $5.48 per share for total consideration of $221.9 million. During 2022, Baytex repurchased and cancelled 24.3 million common shares at an average price of $6.54 per share for total consideration of $159.0 million. The total consideration paid includes the commissions and fees paid as part of the transaction and is recorded as a reduction to shareholders' equity. The shares repurchased and cancelled are accounted for as a reduction in shareholders' capital at historical cost, with any discount paid recorded to contributed surplus and any premium paid recorded to retained earnings.

Dividends

In November 2023, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share which was paid on January 2, 2024 for shareholders of record as at December 15, 2023. On February 28, 2024, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on April 1, 2024 for shareholders on record as at March 15, 2024.

The following dividends were declared by Baytex during the year ended December 31, 2023:

Record Date	Payable Date	Per Share Amount		Dividend Amount
September 15, 2023	October 2, 2023	$0.0225	$	19,138
December 15, 2023	January 2, 2024	$0.0225		18,381
Total dividends declared			**$**	**37,519**

12. SHARE-BASED COMPENSATION PLAN

For the year ended December 31, 2023, the Company recorded total share-based compensation expense of $37.7 million ($29.1 million for the year ended December 31, 2022) which is comprised of $16.2 million of non-cash expense related to awards assumed in the acquisition of Ranger which were settled with Baytex common shares after closing of the business combination. Total share-based compensation expense for the year ended December 31, 2023 also includes the $21.5 million related to cash-settled awards and the associated equity total return swaps ($25.9 million for the year ended December 31, 2022).

The Company's closing share price on December 31, 2023 was $4.38 (December 31, 2022 - $6.08).

Share Award Incentive Plan

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 directors, officers and employees of the Company and its subsidiaries. Pursuant to the Share Award Incentive Plan, Baytex has the option to settle amounts payable related to Share Awards in cash on the settlement date. 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 exceed 3.8% of the then-issued and outstanding common shares.

A restricted award entitles the holder of each award to receiveone common share of Baytex or the equivalent cash value at the time of vesting. A performance award entitles the holder of each award to receive between zero and two common shares or the cash equivalent value on vesting; the number of common shares issued is determined by a performance multiplier. The multiplier can range between zero and two and is calculated based on a number of factors determined and approved by the Board of Directors on an annual basis. The multiplier is dependent on the performance of the Company relative to predefined corporate performance measures for a particular period. The number Share Awards is adjusted to account for the payment of dividends from the grant date to the applicable issue date. The Share 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 share-based compensation liability.

When Share Awards are accounted for as equity-settled, share-based compensation expense is determined using the fair value of the Share Awards on the grant date which is based on quoted market prices for the Company's common shares. Share Awards vest in equal tranches on the first, second and third anniversaries of the grant date and are expensed over the vesting period using the graded vesting method, with a corresponding increase to contributed surplus. On the vest date, the associated contributed surplus is recognized in shareholders' capital.

In 2022, the Company received approval from its Board of Directors to settle the existing Share Awards with cash under the terms of the Share Award Incentive Plan. As a result, Baytex recognized the fair value of the liability for amortized unvested Share Awards in share-based compensation liability. For the year-ended December 31, 2022, the fair value of the liability recognized exceeded the amount previously recognized in contributed surplus of $4.8 million and the excess was recognized as share-based compensation expense in the period.

Liabilities associated with cash-settled awards are determined based on the fair value of the award at grant date and are subsequently revalued at each period end until the date of settlement. This valuation incorporates the period-end share price, the number of awards outstanding at each period end, and certain management estimates, such as estimated forfeitures and performance multiplier, if applicable. Share-based compensation expense related to cash-settled awards is recognized in the consolidated statements of income (loss) and comprehensive income (loss) over the relevant service period with a corresponding increase or decrease in share-based compensation liability. Classification of the associated short-term and long-term liabilities is dependent on the expected payout dates of the individual awards.

On June 20, 2023, Baytex became the successor to Ranger's Share Award Plan (note 4). Although no new grants will be made under the Ranger Share Award Plan, awards that were outstanding at June 20, 2023 were converted to restricted awards that will be settled in shares of Baytex or with cash, with the quantity outstanding adjusted based on the exchange ratio for the business combination with Ranger.

The weighted average fair value of Share Awards granted during the year ended December 31, 2023 was $5.40 per restricted and performance award ($6.08 for the year ended December 31, 2022).

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, 2021	**2,093**	**7,381**	**9,474**
Granted	68	1,391	1,459
Vested	(1,377)	(3,630)	(5,007)
Forfeited	(22)	(346)	(368)
Balance, December 31, 2022	**762**	**4,796**	**5,558**
Granted	41	2,641	2,682
Assumed on corporate acquisition [(1)]	10,789	—	10,789
Vested	(9,302)	(3,767)	(13,069)
Forfeited	(11)	(315)	(326)
Balance, December 31, 2023	**2,279**	**3,355**	**5,634**

(1) Following the closing of the transaction, holders of awards outstanding under Ranger's Share Award Plan were entitled to Baytex common shares rather than Ranger common shares with adjustment to the quantity outstanding based on the exchange ratio for Ranger shares. The fair value of share awards allocated to consideration was based on the service period that had occurred prior to the acquisition date (note 4) while the remaining fair value of the share awards assumed by Baytex will be recognized over the remaining future service periods.

Incentive Award Plan

Baytex has an Incentive Award Plan whereby the participants of the plan are entitled to receive a cash payment equal to the value of one Baytex common share per incentive award at the time of vesting. The incentive awards vest in equal tranches on the first, second and third anniversaries of the grant date using the graded vesting method. The cumulative expense is recognized at fair value at each period end and is included in share-based compensation liability.

During the year ended December 31, 2023, Baytex granted 2.6 million awards under the Incentive Award Plan at a fair value of $5.35 per award (1.4 million awards at $5.70 per award for the year ended December 31, 2022). At December 31, 2023 there were 4.5 million awards outstanding under the Incentive Award Plan (December 31, 2022 - 5.1 million).

Deferred Share Unit Plan ("DSU Plan")

Baytex has a DSU Plan whereby each independent director of Baytex is entitled to receive a cash payment equal to the value of one Baytex common share per DSU award on the date at 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 share-based compensation liability.

During the year ended December 31, 2023, Baytex granted 0.3 million awards under the DSU Plan at a fair value of $5.15 per award (0.2 million awards at $5.68 per award for the year ended December 31, 2022). At December 31, 2023, there were 1.2 million awards outstanding under the DSU Plan (December 31, 2022 - 1.0 million).

Equity Total Return Swaps

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 Company's cash-settled plans including the Incentive Award Plan, the DSU Plan and the Share Award Incentive Plan, at the fair value determined on the grant date.

At December 31, 2023, an asset of $1.0 million associated with the equity total return swap was included in trade receivables (December 31, 2022 - $21.2 million).

13. NET (LOSS) INCOME 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					
	2023			2022		
	Net (loss) income	**Weighted average common shares (000's)**	**Net (loss) income per share**	Net income	Weighted average common shares (000's)	Net income per share
Net (loss) income - basic	**$ (233,356)**	**704,896**	**$ (0.33)**	$ 855,605	557,986	$ 1.53
Dilutive effect of share awards	**—**	**—**	**—**	—	5,849	—
Net (loss) income - diluted	**$ (233,356)**	**704,896**	**$ (0.33)**	$ 855,605	563,835	$ 1.52

For the year ended December 31, 2023, all share awards were excluded from the calculation of diluted loss per share as their effect was anti-dilutive given the Company recorded a loss. For the year ended December 31, 2022, 0.3 million share awards were excluded from the calculation of diluted income per share as their effect was anti-dilutive.

14. 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					
	2023			2022		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 574,910**	**$ 1,454,213**	**$ 2,029,123**	$ 693,043	$ 777,506	$ 1,470,549
Heavy oil	**1,081,549**	**—**	**1,081,549**	1,102,076	—	1,102,076
NGL	**23,174**	**122,823**	**145,997**	30,847	89,658	120,505
Natural gas	**49,388**	**76,564**	**125,952**	100,595	95,320	195,915
Total petroleum and natural gas sales	**$ 1,729,021**	**$ 1,653,600**	**$ 3,382,621**	$ 1,926,561	$ 962,484	$ 2,889,045

Included in trade receivables at December 31, 2023 is $271.1 million of accrued receivables related to delivered volumes (December 31, 2022 - $180.3 million).

15. INCOME TAXES

The provision for income taxes has been computed as follows:

	Years Ended December 31	
	2023	2022
Net (loss) income before income taxes	**$ (516,582)**	$ 890,915
Expected income taxes at the statutory rate of 24.64% (2022 – 24.80%) [1]	**(127,286)**	220,947
Increase (decrease) in income taxes resulting from:		
Effect of foreign exchange	**(2,089)**	4,976
Effect of rate adjustments for foreign jurisdictions	**5,062**	(25,522)
Effect of change in deferred tax benefit not recognized [2]	**6,347**	(129,931)
Effect of internal debt restructuring [3]	**(186,460)**	(44,762)
Repatriation and related taxes	**13,565**	—
Adjustments, assessments and other	**7,635**	9,602
Income tax (recovery) expense	**$ (283,226)**	$ 35,310

(1) The expected income tax rate decreased due to changes in the provincial apportionment of Canadian income.
(2) A deferred tax asset of $40.4 million remains unrecognized due to uncertainty surrounding future commodity prices and future capital gains (December 31, 2022 - $14.4 million). These deferred income tax assets relate to capital losses of $101.8 million and non-capital losses of $113.0 million.
(3) A deferred income tax asset has been recognized immediately after the closing of the Ranger acquisition due to effects of the transaction structuring.

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. Following objections and submissions, in November 2023 the CRA issued notices of confirmation regarding their prior reassessments. In February 2024, Baytex filed notices of appeal with the Tax Court of Canada and we estimate it could take between two and three years to receive a judgment. The reassessments do not require us to pay any amounts in order to participate in the appeals process. 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.

We remain confident that the tax filings of the affected entities are correct and are vigorously defending our tax filing positions. In addition, we have purchased $272.5 million of insurance coverage for a premium of $50.3 million to help manage the litigation risk associated with this matter. The most recent reassessments issued by the CRA assert taxes owing by the trusts (described below) of $244.8 million, late payment interest of $166.6 million as of the date of the reassessments, and a late filing penalty in respect of the 2011 tax year of $4.1 million.

By way of background, we acquired several privately held commercial trusts in 2010 with accumulated non-capital losses of $591.0 million (the "Losses"). The Losses were subsequently deducted in computing the taxable income of those trusts. The reassessments, as confirmed in November 2023, disallow the deduction of the Losses for two reasons. Firstly, the reassessments allege that (i) the trusts were resettled, and (ii) the resulting successor trusts were not able to access the losses of the predecessor trusts. Secondly, the reassessments allege that the general anti-avoidance rule of the Income Tax Act (Canada) operates to deny the deduction of the losses. If, after exhausting available appeals, the deduction of Losses continues to be disallowed, either the trusts or their corporate beneficiary will owe cash taxes, late payment interest and potentially penalties. The amount of cash taxes owing, late payment interest and potential penalties are dependent upon the taxpayer(s) ultimately liable (the trusts or their corporate beneficiary) and the amount of unused tax shelter available to those/that taxpayer(s) to offset the reassessed income, including tax shelter from future years that may be carried back and applied to prior years.

For the year-ended December 31, 2023, Baytex forecasts effective tax rates will exceed 15% in all jurisdictions in which we operate and therefore does not anticipate owing any top-up taxes under Pillar Two legislation.

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

As at	January 1, 2023	Recognized in Net Income	Business Combination	Foreign Currency Translation Adjustment	**December 31, 2023**
Taxable temporary differences:					
Petroleum and natural gas properties	$ (807,514)	$ 200,623	$ (111,131)	$ 11,921	**$ (706,101)**
Financial derivatives	(2,506)	4,506	(4,738)	—	**(2,738)**
Other	(20,951)	8,225	—	(320)	**(13,046)**
Deductible temporary differences:					
Asset retirement obligations	145,275	(873)	6,575	(121)	**150,856**
Non-capital losses [1][2]	416,131	79,343	156,385	(4,298)	**647,561**
Finance costs	60,951	5,805	53,761	(5,237)	**115,280**
Net deferred income tax (liability) asset [3]	$ (208,614)	$ 297,629	$ 100,852	$ 1,945	**$ 191,812**

(1) Non-capital loss carry-forwards at December 31, 2023 totaled $3.2 billion, of which $2.6 billion will expire from 2033 to 2040, and $575.7 million does not have an expiry date.

(2) A deferred income tax asset of $213.1 million has been recognized in respect of non-capital losses of a wholly owned financing subsidiary of Baytex; which losses will be offset against future interest income to be earned as a result of an internal debt restructuring.

(3) The net deferred income tax asset is comprised of a deferred income tax asset of $213.1 million and a deferred income tax liability of $21.3 million.

As at	January 1, 2022	Recognized in Net Loss	Foreign Currency Translation Adjustment	**December 31, 2022**
Taxable temporary differences:				
Petroleum and natural gas properties	$ (760,579)	$ (18,081)	$ (28,854)	**$ (807,514)**
Financial derivatives	—	(2,506)	—	**(2,506)**
Other	(21,616)	(1,137)	1,802	**(20,951)**
Deductible temporary differences:				
Asset retirement obligations	185,336	(40,693)	632	**145,275**
Financial derivatives	31,492	(31,492)	—	**—**
Non-capital losses [1]	342,884	61,005	12,242	**416,131**
Finance costs	55,027	1,188	4,736	**60,951**
Net deferred income tax liability	$ (167,456)	$ (31,716)	$ (9,442)	**$ (208,614)**

(1) Non-capital loss carry-forwards at December 31, 2022 totaled $1.8 billion and will expire from 2033 to 2040.

16. FINANCING AND INTEREST

	Years Ended December 31	
	2023	2022
Interest on Credit Facilities	**$ 56,713**	$ 19,550
Interest on long-term notes	**102,426**	60,643
Interest on lease obligations	**684**	193
Cash interest	**$ 159,823**	$ 80,386
Amortization of debt issue costs	**11,944**	6,286
Accretion of asset retirement obligations (note 10)	**20,406**	15,683
Early redemption expense	**—**	2,462
Financing and interest	**$ 192,173**	$ 104,817

17. FOREIGN EXCHANGE

	Years Ended December 31	
	2023	2022
Unrealized foreign exchange (gain) loss	**$ (14,300)**	$ 45,073
Realized foreign exchange loss (gain)	**3,452**	(1,632)
Foreign exchange (gain) loss	**$ (10,848)**	$ 43,441

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial assets and liabilities are comprised of cash, trade receivables, trade payables, financial derivatives, Credit Facilities and long-term notes. The fair value of cash, trade receivables, trade payables and dividends payable approximates carrying value due to the short term to maturity. 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, 2023		December 31, 2022		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL					
Financial Derivatives	**$ 23,274**	**$ 23,274**	$ 10,105	$ 10,105	Level 2
Total	**$ 23,274**	**$ 23,274**	$ 10,105	$ 10,105	
Amortized cost					
Cash	**$ 55,815**	**$ 55,815**	$ 5,464	$ 5,464	—
Trade receivables	**339,405**	**339,405**	222,108	222,108	
Total	**$ 395,220**	**$ 395,220**	$ 227,572	$ 227,572	
Financial Liabilities					
Amortized cost					
Trade payables	**$ (477,295)**	**$ (477,295)**	$ (227,332)	$ (227,332)	—
Dividends payable	**(18,381)**	**(18,381)**	—	—	—
Credit Facilities	**(848,749)**	**(864,736)**	(383,031)	(385,394)	—
Long-term notes	**(1,562,361)**	**(1,653,118)**	(547,598)	(563,292)	Level 1
Total	**$ (2,906,786)**	**$ (3,013,530)**	$ (1,157,961)	$ (1,176,018)	

Baytex classifies the fair value of financial instruments according to the following hierarchy based on the number 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.

There were no transfers between Level 1 and Level 2 during the years ended December 31, 2023 or 2022.

Foreign Currency Risk

In entities with a Canadian dollar functional currency, 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 and crude oil sales based on U.S. dollar benchmark prices. 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 $12.3 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, 2023	December 31, 2022	**December 31, 2023**	December 31, 2022
U.S. dollar denominated	**US$17,923**	US$6,980	**US$1,249,725**	US$430,171

Interest Rate Risk

The Company's interest rate risk arises from borrowing at floating rates under the Credit Facilities (note 8). Based on the principal outstanding on the Credit Facilities as at December 31, 2023, a 100 basis points change in interest rates would impact net income or loss before income taxes by approximately $8.6 million for an annual period.

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.

The reported value of commodity financial derivatives is sensitive to changes in forecasted commodity prices. For crude oil contracts outstanding as at December 31, 2023, a US$1.00/bbl change in the underlying benchmark crude oil prices would impact net income before income taxes by approximately $13.4 million. For natural gas and natural gas liquids contracts outstanding as at December 31, 2023, a US$0.25 change in the underlying benchmark natural gas or natural gas liquids prices would impact net income or loss before income taxes by approximately $4.7 million.

Financial Derivative Contracts

Baytex had the following commodity financial derivative contracts outstanding as at February 28, 2024.

	Period	Volume	Price/Unit [1]	Index
Oil				
Basis differential	Jan 2024 to Jun 2024	4,000 bbl/d	Baytex pays: WCS differential at Hardisty Baytex receives: WCS differential at Houston less US$8.10/bbl	WCS
Basis differential	July 2024 to Dec 2024	4,000 bbl/d	Baytex pays: WCS differential at Hardisty Baytex receives: WCS differential at Houston less US$8.40/bbl	WCS
Basis differential [2]	July 2024 to Dec 2024	5,000 bbl/d	Baytex pays: WCS differential at Hardisty Baytex receives: WCS differential at Houston less US$8.18/bbl	WCS
Basis differential [2]	Apr 2024 to Dec 2024	3,000 bbl/d	Baytex pays: WCS differential at Hardisty Baytex receives: WCS differential at Houston less US$8.27/bbl	WCS
Basis differential [2]	July 2024 to Dec 2024	3,000 bbl/d	WTI less US$13.70/bbl	WCS
Basis differential	Jan 2024 to Dec 2024	1,500 bbl/d	WTI less US$2.65/bbl	MSW
Basis differential [2]	Apr 2024 to Dec 2024	1,250 bbl/d	WTI less US$3.40/bbl	MSW
Basis differential [2]	July 2024 to Dec 2024	2,500 bbl/d	WTI less US$2.85/bbl	MSW
Collar	Jan 2024 to Mar 2024	10,400 bbl/d	US$60.00/US$100.00	WTI
Collar	Jan 2024 to Jun 2024	24,500 bbl/d	US$60.00/US$100.00	WTI
Collar	July 2024 to Dec 2024	2,500 bbl/d	US$60.00/US$90.21	WTI
Collar	Apr 2024 to Jun 2024	11,750 bbl/d	US$60.00/US$100.00	WTI
Collar	July 2024 to Dec 2024	2,500 bbl/d	US$60.00/US$94.15	WTI
Collar	July 2024 to Dec 2024	10,000 bbl/d	US$60.00/US$100.00	WTI
Collar	July 2024 to Sep 2024	10,000 bbl/d	US$60.00/US$100.00	WTI
Collar	Oct 2024 to Dec 2024	2,500 bbl/d	US$60.00/US$100.00	WTI
Collar [2]	July 2024 to Dec 2024	9,000 bbl/d	US$60.00/US$84.58	WTI
Collar [2]	Oct 2024 to Dec 2024	7,000 bbl/d	US$60.00/US$86.43	WTI
Natural Gas				
Fixed Sell	Jan 2024 to Mar 2024	3,500 mmbtu/d	US$3.5025	NYMEX
Collar	Jan 2024 to Mar 2024	11,538 mmbtu/d	US$2.50/US$3.65	NYMEX
Collar	Apr 2024 to Jun 2024	11,538 mmbtu/d	US$2.33/US$3.00	NYMEX
Collar	Jan 2024 to Dec 2024	2,500 mmbtu/d	US$3.00/US$4.06	NYMEX
Collar	Jan 2024 to Dec 2024	2,500 mmbtu/d	US$3.00/US$4.09	NYMEX
Collar	Jan 2024 to Dec 2024	5,000 mmbtu/d	US$3.00/US$4.10	NYMEX
Collar	Jan 2024 to Dec 2024	8,500 mmbtu/d	US$3.00/US$4.15	NYMEX
Collar	Jan 2024 to Dec 2024	5,000 mmbtu/d	US$3.00/US$4.19	NYMEX
Natural Gas Liquids				
Fixed Sell	Jan 2024 to Mar 2024	34,364 gallon/d	US$0.2280/gallon	Mt. Belvieu Non-TET Ethane

(1) Based on the weighted average price per unit for the period.
(2) Contracts entered subsequent to December 31, 2023.

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

	Years Ended December 31	
	2023	2022
Realized financial derivatives (gain) loss	**$ (36,212)**	$ 334,481
Unrealized financial derivatives loss (gain)	**11,517**	(135,471)
Financial derivatives (gain) loss	**$ (24,695)**	$ 199,010

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 management of forecasted and actual cash flows from operating, financing and investing activities, available capacity under existing credit facility arrangements, and opportunities to issue additional common shares.

The timing of cash outflows relating to financial liabilities as at December 31, 2023 is outlined in the table below:

	Total	2024	2025-2026	2027-2028	2029 and beyond
Trade payables	**$ 477,295**	$ 477,295	$ —	$ —	$ —
Credit Facilities - principal	**864,736**	—	864,736	—	—
Long-term notes - principal [(1)]	**1,597,475**	—	—	541,114	1,056,361
Interest on long-term notes [(2)]	**722,732**	137,138	274,276	191,515	119,803
	$ 3,662,238	**$ 614,433**	**$ 1,139,012**	**$ 732,629**	**$ 1,176,164**

(1) The US$409.8 million principal amount of 8.75% senior unsecured notes is due April 1, 2027 and the US$800.0 million principal amount of 8.50% senior unsecured notes is due April 30, 2030.

(2) 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, 2023, the Company is exposed to credit risk with respect to its cash, trade receivables and financial derivatives. Baytex manages these risks through the selection and monitoring of credit-worthy counterparties.

Most of the Company's trade 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. 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. 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 receivables at December 31, 2023 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.

Should the Company determine that the ultimate collection of a receivable is in doubt, the carrying amount of trade 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, 2023, allowance for doubtful accounts was $1.5 million (December 31, 2022 - $2.5 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. Baytex has estimated the lifetime expected credit loss as at and for the year ended December 31, 2023 to be nominal.

The Company's trade receivables, net of the allowance for doubtful accounts, were aged as follows at December 31, 2023.

Trade Receivables Aging	**December 31, 2023**	December 31, 2022
Current (less than 30 days)	**$ 321,450**	$ 216,345
31-60 days	**14,836**	1,993
61-90 days	**461**	766
Past due (more than 90 days)	**2,658**	3,005
	$ 339,405	$ 222,108

19. SUPPLEMENTAL INFORMATION

Changes in Non-Cash Working Capital Items

	Years Ended December 31	
	2023	2022
Trade receivables	**$ (117,297)**	$ (54,963)
Prepaids and other assets	**(76,882)**	(113)
Trade payables	**236,560**	42,337
Share-based compensation liability	**(18,340)**	48,375
Dividends payable	**18,381**	—
Non-cash working capital acquired (note 4)	**(230,012)**	—
	$ (187,590)	$ 35,636
Changes in non-cash working capital related to:		
Operating activities	**$ (220,895)**	$ 26,072
Financing activities	**(3,068)**	—
Investing activities	**46,810**	9,401
Transfers from equity	**—**	4,791
Foreign currency translation on non-cash working capital	**(10,437)**	(4,628)
	$ (187,590)	$ 35,636

Income Statement Presentation

Baytex's consolidated statements of income (loss) and comprehensive income (loss) are prepared 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	
	2023	2022
Operating	**$ 17,975**	$ 11,814
General and administrative	**49,633**	35,935
Total employee compensation costs	**$ 67,608**	$ 47,749

20. 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 (note 22). These obligations as of December 31, 2023 and the expected timing of funding of these obligations, are noted in the table below.

	Total	2024	2025-2026	2027-2028	2029 and beyond
Processing agreements	**$ 5,642**	$ 618	$ 1,003	$ 563	$ 3,458
Transportation agreements	**212,400**	52,691	94,866	47,601	17,242
Total	**$ 218,042**	**$ 53,309**	**$ 95,869**	**$ 48,164**	**$ 20,700**

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 (note 10). The present value of the future estimated abandonment and reclamation costs are included in the asset retirement obligations presented in the statement of financial position. Programs to abandon and reclaim wellsites and facilities are undertaken regularly in accordance with applicable legislative requirements.

21. RELATED PARTIES

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

	Years Ended December 31	
	2023	2022
Short-term employee benefits	**$ 7,753**	$ 6,868
Share-based compensation	**9,924**	9,043
Termination payments	**—**	1,758
Total compensation for key management personnel	**$ 17,677**	$ 17,669

22. CAPITAL MANAGEMENT

The Company's capital management objective is to maintain a strong balance sheet that provides financial flexibility to execute its development programs, provide returns to shareholders and optimize its portfolio through strategic acquisitions. Baytex strives to actively manage its capital structure in response to changes in economic conditions. At December 31, 2023, the Company's capital structure was comprised of shareholders' capital, long-term notes, trade receivables, prepaids and other assets, trade payables, share-based compensation liability, dividends payable, cash and the Credit Facilities.

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

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

Net Debt

The Company uses net debt to monitor its current financial position and to evaluate existing sources of liquidity. The Company defines net debt to be the sum of our Credit Facilities and long-term notes outstanding adjusted for unamortized debt issuance costs, trade payables, dividends payable, share-based compensation liability, other long-term liabilities, cash, trade receivables and prepaids and other assets. 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, 2023	December 31, 2022
Credit Facilities	**$ 848,749**	$ 383,031
Unamortized debt issuance costs - Credit Facilities (note 8)	**15,987**	2,363
Long-term notes	**1,562,361**	547,598
Unamortized debt issuance costs - Long-term notes (note 9)	**35,114**	6,999
Trade payables	**477,295**	227,332
Dividends payable	**18,381**	—
Share-based compensation liability	**35,732**	54,072
Other long-term liabilities	**19,147**	—
Cash	**(55,815)**	(5,464)
Trade receivables	**(339,405)**	(222,108)
Prepaids and other assets	**(83,259)**	(6,377)
Net Debt	**$ 2,534,287**	$ 987,446

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 and settlement of abandonment obligations. Adjusted funds flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital, asset retirements obligations settled during the applicable period, transaction costs and cash premiums on derivatives.

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

	Years Ended December 31	
	2023	2022
Cash flows from operating activities	**$ 1,295,731**	$ 1,172,872
Change in non-cash working capital	**220,895**	(26,072)
Asset retirement obligations settled	**26,416**	18,351
Transaction costs	**49,045**	—
Cash premiums on derivatives	**2,263**	—
Adjusted Funds Flow	**$ 1,594,350**	$ 1,165,151

BAYTEX ENERGY CORP. **Exhibit 99.3**
Management's Discussion and Analysis
For the years ended December 31, 2023 and 2022
Dated February 28, 2024

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, 2023 and 2022. This information is provided as of February 28, 2024. 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, 2023 ("Q4/2023" and "2023") have been compared with the results for the three months and year ended December 31, 2022 ("Q4/2022" and "2022"). 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, 2023 and 2022, together with the accompanying notes and the Annual Information Form ("AIF") for the year ended December 31, 2023. These documents and additional information about Baytex are accessible on the SEDAR+ website at www.sedarplus.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 issued 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" and "net debt" 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 operated and non-operated assets in Texas.

On June 20, 2023, Baytex and Ranger Oil Corporation ("Ranger") completed the merger of the two companies (the "Merger") whereby Baytex acquired all of the issued and outstanding common shares of Ranger. The Merger increased our Eagle Ford scale and provides an operating platform to effectively allocate capital across the Western Canadian Sedimentary Basin and the Eagle Ford. Production from the Ranger assets is approximately 80% weighted towards high netback light oil and liquids and is primarily operated which increases our ability to effectively allocate capital.

We issued 311.4 million common shares, paid $732.8 million in cash and assumed $1.1 billion of Ranger's net debt[1]. The cash portion of the transaction was funded with an expanded US$1.1 billion credit facility, a US$150 million two-year term loan facility and the net proceeds from the issuance of US$800 million senior unsecured notes due 2030.

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

2023 ANNUAL HIGHLIGHTS

Baytex delivered strong operating and financial results in 2023. Our annual results include six months of operations following the Merger with Ranger and demonstrate the strength of our increased scale and diversified North American oil-weighted portfolio. Annual production of 122,154 boe/d was consistent with our revised annual guidance of 121,500 to 122,000 boe/d and reflects strong results from our drilling programs in Western Canada and the Eagle Ford in Texas. We invested $1.0 billion in exploration and development expenditures and generated free cash flow(1) of $543.6 million in 2023.

Exploration and development expenditures totaled $1.0 billion for 2023. In the U.S. we invested $549.6 million during 2023 and production averaged 60,997 boe/d which is higher than 28,245 boe/d in 2022 due to the Merger. We invested $463.2 million in Canada in 2023 and generated production of 61,157 boe/d during 2023 compared to 55,275 boe/d in 2022 which reflects growth driven by strong well performance from our heavy oil operations at Peavine.

Oil prices were lower in 2023 as a result of global supply growth which has resulted in a more balanced crude market relative to 2022 when prices were elevated as the global supply shortfall was exacerbated by uncertainty related to Russian supply. The average WTI benchmark price for 2023 was US$77.62/bbl which was US$16.61/bbl lower than 2022 when WTI averaged US$94.23/bbl.

Adjusted funds flow(2) of $1.6 billion in 2023 was higher than $1.2 billion for 2022 which reflects higher production following the Merger partially offset by lower realized pricing due to the decline in benchmark prices. Free cash flow of $543.6 million in 2023 was lower than $621.5 million for 2022 due to lower benchmark prices, inflationary pressures in Canada and the U.S. along with increased development activity following the Merger. Cash flows from operating activities increased to $1.3 billion in 2023 compared to $1.2 billion in 2022. The net loss of $233.4 million for 2023 includes an impairment loss of $833.7 million compared to net income of $855.6 million in 2022 which included impairment reversals of $267.7 million.

Net debt(2) of $2.5 billion at December 31, 2023 was $1.5 billion higher than $1.0 billion at December 31, 2022 due to the cash consideration paid and net debt assumed in conjunction with the Merger. Since the Merger on June 20, 2023, we have paid down $280.6 million of net debt and increased our shareholder returns to 50% of free cash flow which allowed us to increase our share buyback program and introduce a dividend. The remainder of our free cash flow will be allocated to the balance sheet.

On June 23, 2023, we renewed our Normal Course Issuer Bid ("NCIB") with the Toronto Stock Exchange for a share buyback program for up to 68.4 million shares (10% of our public float at the time). During 2023 we repurchased 40.5 million shares for $221.9 million representing 5% of the outstanding shares at the inception of the NCIB renewal. On October 2, 2023 and January 2, 2024, we paid a quarterly cash dividend of CDN$0.0225 per share as part of our shareholder returns commitment. On February 28, 2024, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on April 1, 2024 for shareholders of record on March 15, 2024. These dividends are designated as “eligible dividends” for Canadian income tax purposes. For U.S. income tax purposes, Baytex’s dividends are considered “qualified dividends.”

(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

GUIDANCE

Our 2024 annual guidance includes exploration and development expenditures of $1.2 - $1.3 billion and is designed to generate annual production of 150,000 - 156,000 boe/d. Our annual production guidance remains unchanged despite weather-related disruptions in Texas that we estimate will result in Q1/2024 production that is approximately 2,000 boe/d lower than our budget expectation.

The following table compares our 2023 revised annual guidance and 2024 annual guidance to our 2023 results. Production, exploration and development expenditures, and expenses were relatively consistent with our revised annual guidance for 2023 which reflects our ongoing efforts to deliver strong operating results while we maintain a competitive cost structure. A higher proportion of our 2024 production will be from the Eagle Ford which will result in a modest increase in our per unit expected transportation costs for 2024 relative to our 2023 results along with a decrease in our operating costs. We continue to use free cash flow for debt repayment and expect cash interest of $3.40/boe in 2024 compared to $3.58/boe in 2023.

	2023 Revised Annual Guidance [1]	2023 Results	2024 Annual Guidance [2]
Exploration and development expenditures	~ $1,035 million	$1,012.8 million	$1.2 - $1.3 billion
Production (boe/d)	121,500 - 122,000 boe/d	122,154 boe/d	150,000 - 156,000
Expenses:			
Average royalty rate [3]	21.0% - 22.0%	21.2 %	23%
Operating [4]	~ $12.75/boe	$12.80/boe	$11.25 - $12.00/boe
Transportation [4]	~ $2.10/boe	$2.00/boe	$2.35 - $2.55/boe
General and administrative [4]	$80 million ($1.80/boe)	$70 million ($1.57/boe)	$92 million ($1.65/boe)
Cash Interest [4]	$156 million ($3.50/boe)	$160 million ($3.58/boe)	$190 million ($3.40/boe)
Current Income Taxes [5]	$14 million ($0.31/boe)	$11 million ($0.24/boe)	$40 million ($0.72/boe)
Leasing expenditures	$13 million	$12 million	$12 million
Asset retirement obligations settled	$25 million	$26 million	$30 million

(1) As announced on November 2, 2023.
(2) As announced on December 6, 2023.
(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.
(5) Current income tax expense per boe is calculated as current income tax expense divided by barrels of oil equivalent production volume for the applicable period.

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 operated and non-operated assets in Texas.

Production

	Years Ended December 31					
	2023			2022		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**15,698**	**37,691**	**53,389**	16,060	17,041	33,101
Heavy oil	**35,460**	**—**	**35,460**	28,993	—	28,993
Natural Gas Liquids ("NGL")	**2,090**	**12,214**	**14,304**	1,896	5,679	7,575
Total liquids (bbl/d)	**53,248**	**49,905**	**103,153**	46,949	22,720	69,669
Natural gas (mcf/d)	**47,454**	**66,556**	**114,010**	49,954	33,146	83,101
Total production (boe/d)	**61,157**	**60,997**	**122,154**	55,275	28,245	83,519
Production Mix						
Segment as a percent of total	**50 %**	**50 %**	**100 %**	66 %	34 %	100 %
Light oil and condensate	**26 %**	**62 %**	**44 %**	29 %	60 %	40 %
Heavy oil	**58 %**	**— %**	**29 %**	52 %	— %	35 %
NGL	**3 %**	**20 %**	**12 %**	3 %	20 %	9 %
Natural gas	**13 %**	**18 %**	**15 %**	16 %	20 %	16 %

Production averaged 122,154 boe/d in 2023 compared to 83,519 boe/d in 2022. Production was higher in 2023 primarily due to the production contribution from the properties acquired from Ranger along with our successful development program in Canada.

In Canada, production increased to 61,157 boe/d in 2023 compared to 55,275 boe/d in 2022. The 5,882 boe/d increase in production is primarily due to strong well performance from our Clearwater heavy oil development program at Peavine.

In the U.S., production was 60,997 boe/d in 2023 compared to 28,245 boe/d for 2022. The production from the Merger contributed to the 32,752 boe/d increase in production for 2023 relative to 2022. Production from the acquired Eagle Ford assets is primarily operated and is weighted towards light oil which resulted in a higher proportion of our total production being light oil in 2023.

Total production of 122,154 boe/d for 2023 was consistent with our revised annual guidance of approximately 121,500 - 122,000 boe/d. We expect production in 2024 to average 150,000 - 156,000 boe/d which is consistent with the production for the second half of 2023 and includes the impact of the non-core Viking disposition which was producing approximately 4,000 boe/d when the sale was completed in December 2023.

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 lower throughout 2023 relative to 2022 as a result of global supply growth which has resulted in a more balanced crude oil market relative to 2022 when prices were elevated as the global supply shortfall was exacerbated by uncertainty related to Russian supply. OPEC curtailed production during the second half of 2023 to stabilize the market after a period of weaker prices in the first half of 2023. As a result of these factors, the WTI benchmark price averaged US$77.62/bbl for 2023 which was US$16.61/bbl lower than US$94.23/bbl for 2022 when WTI was higher due to uncertainty around global supply caused by Russia's invasion of Ukraine.

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 typically trades at a premium to WTI as a result of access to global markets. The MEH benchmark averaged US$79.29/bbl during 2023, representing a premium of US$1.67/bbl relative to WTI, compared to US$97.79/bbl or a premium of US$3.57/bbl for 2022. Reduced demand on the Gulf Coast during 2023 resulted in a slightly lower premium compared to 2022 when there was heightened uncertainty over global supply.

Prices for Canadian oil trade at a discount to WTI due to a lack of egress to diversified markets from Western Canada. Differentials for Canadian oil prices relative to WTI fluctuate 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 $100.46/bbl for 2023 compared to $119.95/bbl for 2022. Edmonton par traded at a US$3.18/bbl discount to WTI in 2023 compared to a discount of US$2.07/bbl for 2022.

We compare the price received for our heavy oil production in Canada to the WCS heavy oil benchmark. The WCS benchmark price for 2023 averaged $79.58/bbl compared to $98.94/bbl for 2022. The WCS differential to WTI was US$18.65/bbl in 2023 which is consistent with US$18.21/bbl in 2022.

Natural Gas

Reduced demand for North American gas resulted in lower prices in 2023 relative to 2022 which was impacted by geopolitical factors that caused higher global natural gas prices due to uncertainty of supply to Europe.

Our U.S. natural gas production is priced in reference to the New York Mercantile Exchange ("NYMEX") natural gas index. The NYMEX natural gas benchmark averaged US$2.74/mmbtu for 2023 compared to US$6.64/mmbtu for 2022.

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 $2.93/mcf during 2023 which is lower than $5.56/mcf during 2022.

The following tables compare select benchmark prices and our average realized selling prices for the years ended December 31, 2023 and 2022.

	Years Ended December 31		
	2023	2022	Change
Benchmark Averages			
WTI oil (US$/bbl) [(1)]	**77.62**	94.23	(16.61)
MEH oil (US$/bbl) [(2)]	**79.29**	97.79	(18.50)
MEH oil differential to WTI (US$/bbl)	**1.67**	3.57	(1.90)
Edmonton par oil ($/bbl) [(3)]	**100.46**	119.95	(19.49)
Edmonton par oil differential to WTI (US$/bbl)	**(3.18)**	(2.07)	(1.11)
WCS heavy oil ($/bbl) [(4)]	**79.58**	98.94	(19.36)
WCS heavy oil differential to WTI (US$/bbl)	**(18.65)**	(18.21)	(0.44)
AECO natural gas price ($/mcf) [(5)]	**2.93**	5.56	(2.63)
NYMEX natural gas price (US$/mmbtu) [(6)]	**2.74**	6.64	(3.90)
CAD/USD average exchange rate	**1.3495**	1.3016	0.0479

(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					
	2023			2022		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl) [1]	**$ 100.34**	**$ 105.71**	**$ 104.13**	$ 118.23	$ 125.00	$ 121.72
Heavy oil, net of blending and other expense ($/bbl) [2]	**66.19**	**—**	**66.19**	86.24	—	86.24
NGL ($/bbl) [1]	**30.38**	**27.55**	**27.96**	44.57	43.25	43.58
Natural gas ($/mcf) [1]	**2.83**	**3.15**	**3.02**	5.52	7.88	6.46
Total sales, net of blending and other expense ($/boe)[2]	**$ 67.39**	**$ 74.27**	**$ 70.82**	$ 86.10	$ 93.36	$ 88.56

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

Average Realized Sales Prices

Our total sales, net of blending and other expense per boe[1] was $70.82/boe for 2023 compared to $88.56/boe for 2022. In Canada, our realized sales price of $67.39/boe for 2023 was lower than $86.10/boe for 2022 and our realized sales price in the U.S. of $74.27/boe in 2023 decreased from $93.36/boe in 2022. The decrease in our realized price in Canada and the U.S. for 2023 was a result of lower North American benchmark prices relative to 2022.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Our realized light oil and condensate price[2] in 2023 was $100.34/bbl compared to $118.23/bbl in 2022. The decrease in our realized light oil and condensate price for 2023 was primarily a result of lower benchmark prices. Our realized price represents a discount of $0.12/bbl to the Edmonton par benchmark which reflects higher Duvernay production in the second half of 2023 which resulted in a narrower discount relative to $1.72/bbl in 2022.

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 $105.71/bbl for 2023 compared to $125.00/bbl for 2022. Expressed in U.S. dollars, our realized light oil and condensate price of US$78.33/bbl for 2023 was lower than US$96.04/bbl in 2022 and represents discounts to MEH of US$0.96/bbl for 2023 which is narrower than a discount of US$1.75/bbl in 2022. The narrower discount in 2023 reflects the additional production from the Merger in the second half of the year when the MEH benchmark was higher relative to the annual average benchmark price.

Our realized heavy oil price, net of blending and other expense[1] averaged $66.19/bbl in 2023 compared to $86.24/bbl in 2022. The $20.05/bbl decrease in our realized heavy oil price, net of blending and other expense is consistent with a $19.36/bbl decrease in WCS benchmark in 2023 compared to 2022.

Our realized NGL price[2] as a percentage of WTI will vary based on the product mix of our NGL volumes and changes in the market prices of the underlying products. Our realized NGL price was $27.96/bbl in 2023 or 27% of WTI (expressed in Canadian dollars) compared to $43.58/bbl or 36% of WTI (expressed in Canadian dollars) in 2022. Our realized NGL price in Canada and the U.S. was lower as a percentage of WTI in 2023 relative to 2022 which reflects lower demand as a result of increased production in North America.

We compare our realized natural gas price in the U.S. to the NYMEX benchmark and to the AECO benchmark price in Canada. A portion of our natural gas sales in Canada and the U.S. are based on the respective daily index prices which fluctuate independently from the associated monthly index prices. Our realized natural gas price[2] in Canada was $2.83/mcf for 2023 compared to $5.52/mcf for 2022. In the U.S., our realized natural gas price was US$2.33/mcf for 2023 compared to US$6.05/mcf for 2022. The decrease in our realized gas price in Canada and the U.S. is consistent with the decreases in the AECO monthly and NYMEX monthly benchmark prices in 2023 compared to 2022.

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

PETROLEUM AND NATURAL GAS SALES

	Years Ended December 31					
	2023			2022		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 574,910**	**$ 1,454,213**	**$ 2,029,123**	$ 693,043	$ 777,506	$ 1,470,549
Heavy oil	**1,081,549**	**—**	**1,081,549**	1,102,076	—	1,102,076
NGL	**23,174**	**122,823**	**145,997**	30,847	89,658	120,505
Total liquids sales	**1,679,633**	**1,577,036**	**3,256,669**	1,825,966	867,164	2,693,130
Natural gas sales	**49,388**	**76,564**	**125,952**	100,595	95,320	195,915
Total petroleum and natural gas sales	**1,729,021**	**1,653,600**	**3,382,621**	1,926,561	962,484	2,889,045
Blending and other expense	**(224,802)**	**—**	**(224,802)**	(189,454)	—	(189,454)
Total sales, net of blending and other expense[1]	**$ 1,504,219**	**$ 1,653,600**	**$ 3,157,819**	$ 1,737,107	$ 962,484	$ 2,699,591

(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 $3.2 billion for 2023 increased $458.2 million from $2.7 billion for 2022. The Merger with Ranger along with higher production from our successful development programs resulted in an increase in total sales in 2023 relative to 2022 partially offset by the effect of lower benchmark prices.

In Canada, total sales, net of blending and other expense, was $1.5 billion for 2023 which is a decrease of $232.9 million from $1.7 billion reported for 2022. The decrease in total petroleum and natural gas sales was the result of lower realized pricing for 2023 relative to 2022 which resulted in a $417.7 million decrease in total sales, net of blending and other expense. The effect of lower realized pricing was partially offset by higher production which resulted in a $184.8 million increase in total sales, net of blending and other expense, relative to 2022.

In the U.S., petroleum and natural gas sales of $1.7 billion in 2023 was $691.1 million higher than $962.5 million reported for 2022. Higher production in 2023 relative to 2022 was primarily due to the Merger with Ranger and contributed to a $1.1 billion increase in total petroleum and natural gas sales which was partially offset by lower realized pricing which resulted in a $425.0 million decrease in total petroleum and natural gas sales.

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 depending on 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, 2023 and 2022.

	Years Ended December 31					
	2023			2022		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 213,148**	**$ 456,644**	**$ 669,792**	$ 277,428	$ 285,536	$ 562,964
Average royalty rate [1][2]	**14.2 %**	**27.6 %**	**21.2 %**	16.0 %	29.7 %	20.9 %
Royalties per boe [3]	**$ 9.55**	**$ 20.51**	**$ 15.02**	$ 13.75	$ 27.70	$ 18.47

(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 2023 were $669.8 million or 21.2% of total sales, net of blending and other expense, compared to $563.0 million or 20.9% in 2022. Total royalty expense was higher in 2023 due to higher total sales, net of blending and other expense, relative to 2022. Our average royalty rate of 21.2% for 2023 was higher than 20.9% for 2022 due to a higher proportion of our production being from the Eagle Ford in 2023 which has a higher royalty rate than our Canadian properties. Our average royalty rate of 21.2% for 2023 was consistent with expectations and our annual guidance range of 21.0% - 22.0% for 2023.

In Canada, the average royalty rate[1] was 14.2% in 2023 which was lower than 16.0% for 2022 and reflects lower benchmark prices for our production in Canada. In the U.S., the average royalty rate was 27.6% for 2023 which is lower than 29.7% for 2022 due to production contributed by the acquired Ranger assets which have a lower royalty rate relative to our legacy non-operated Eagle Ford properties.

We expect our average royalty rate to be approximately 23% for 2024 which reflects a higher proportion of our production from the Eagle Ford in 2024 relative to 2023 with a full year of results including the Merger.

(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.

OPERATING EXPENSE

	Years Ended December 31					
	2023			2022		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 368,605**	**$ 202,234**	**$ 570,839**	$ 327,894	$ 94,772	$ 422,666
Operating expense per boe [1]	**$ 16.51**	**$ 9.08**	**$ 12.80**	$ 16.25	$ 9.19	$ 13.86

(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 $570.8 million ($12.80/boe) in 2023 compared to $422.7 million ($13.86/boe) in 2022. Total operating expense for 2023 increased relative to 2022 while per boe operating costs were lower as the Ranger properties have lower per boe operating expenses. Operating expense of $12.80/boe for 2023 was consistent with our revised annual guidance of ~ $12.75/boe.

In Canada, operating expense was $368.6 million ($16.51/boe) for 2023 compared to $327.9 million ($16.25/boe) for 2022. The total operating expenses were higher in Canada as a result of higher production while per boe operating costs in 2023 were relatively consistent with 2022.

Our U.S. operating expense was $202.2 million ($9.08/boe) for 2023 compared to $94.8 million ($9.19/boe) for 2022. Total operating expense in the U.S. was higher in 2023 relative to 2022 with the addition of production from the properties acquired from Ranger. Per boe operating expense in the U.S., expressed in U.S. dollars, was US$6.73/boe for 2023 which is slightly lower than US$7.06/boe for 2022 which reflects the lower per unit operating cost on the acquired operated Eagle Ford properties.

We expect annual operating expense of $11.25 - $12.00/boe for 2024 which reflects a higher proportion of our production from our Eagle Ford properties relative to 2023, which have lower per unit operating costs.

TRANSPORTATION EXPENSE

Transportation expense includes the costs to move production 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 depending on trucking rates and hauling distances as we seek to optimize sales prices. Transportation expense in our U.S. operations reflects the costs incurred to deliver our production to a centralized sales point via truck or pipeline.

The following table compares our transportation expense for the years ended December 31, 2023 and 2022.

	Years Ended December 31					
	2023			2022		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 64,325**	**$ 24,981**	**$ 89,306**	$ 48,561	$ —	$ 48,561
Transportation expense per boe[(1)]	**$ 2.88**	**$ 1.12**	**$ 2.00**	$ 2.41	$ —	$ 1.59

(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 $89.3 million ($2.00/boe) for 2023 compared to $48.6 million ($1.59/boe) for 2022. In Canada, the total transportation expense and per unit costs are higher in 2023 relative to 2022 as a result of additional heavy oil production primarily at Peavine, along with higher trucking rates due to increased fuel surcharges and truck shortages. Transportation expense in the U.S. is consistent with expectations for 2023 and reflects trucking and pipeline transportation costs on our Eagle Ford operations acquired from Ranger.

Transportation expense of $2.00/boe in 2023 was slightly below our revised annual guidance of ~ $2.10/boe for 2023. We expect annual transportation expense of $2.35 - $2.55/boe for 2024 which reflects a higher proportion of our 2024 production from the Eagle Ford.

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 $224.8 million for 2023 compared to $189.5 million for 2022. The increase in blending and other expense is primarily a result of higher heavy oil production and pipeline shipments in 2023 relative to 2022.

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 free cash 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 fluctuate and as new contracts are entered. The following table summarizes the results of our financial derivative contracts for the years ended December 31, 2023 and 2022.

	Years Ended December 31		
($ thousands)	**2023**	2022	Change
Realized financial derivatives gain (loss)			
Crude oil	**$ 35,687**	$ (299,788)	$ 335,475
Natural gas	**525**	(34,693)	35,218
Total	**$ 36,212**	$ (334,481)	$ 370,693
Unrealized financial derivatives (loss) gain			
Crude oil	**$ (17,674)**	$ 136,879	$ (154,553)
Natural gas	**6,157**	5,082	1,075
Equity total return swap	**—**	(6,490)	6,490
Total	**$ (11,517)**	$ 135,471	$ (146,988)
Total financial derivatives gain (loss)			
Crude oil	**$ 18,013**	$ (162,909)	$ 180,922
Natural gas	**6,682**	(29,611)	36,293
Equity total return swap	**—**	(6,490)	6,490
Total	**$ 24,695**	$ (199,010)	$ 223,705

We recorded a financial derivatives gain of $24.7 million for 2023 compared to a loss of $199.0 million for 2022. The realized financial derivatives gain for 2023 of $36.2 million was primarily a result of market prices for crude oil and natural gas settling at levels below the prices set in our derivative contracts. The unrealized financial derivatives loss of $11.5 million for 2023 is primarily due to changes in forecasted crude oil pricing used to revalue the volumes outstanding on our crude oil and natural gas contracts in place at December 31, 2023 relative to December 31, 2022. The fair value of our financial derivative contracts resulted in a net asset of $23.3 million at December 31, 2023 compared to a net asset of $10.1 million at December 31, 2022.

Baytex had the following commodity financial derivative contracts as at February 28, 2024.

	Period	Volume	Price/Unit [1]	Index
Oil				
Basis differential	Jan 2024 to Jun 2024	4,000 bbl/d	Baytex pays: WCS differential at Hardisty Baytex receives: WCS differential at Houston less US$8.10/bbl	WCS
Basis differential	July 2024 to Dec 2024	4,000 bbl/d	Baytex pays: WCS differential at Hardisty Baytex receives: WCS differential at Houston less US$8.40/bbl	WCS
Basis differential [2]	July 2024 to Dec 2024	5,000 bbl/d	Baytex pays: WCS differential at Hardisty Baytex receives: WCS differential at Houston less US$8.18/bbl	WCS
Basis differential [2]	Apr 2024 to Dec 2024	3,000 bbl/d	Baytex pays: WCS differential at Hardisty Baytex receives: WCS differential at Houston less US$8.27/bbl	WCS
Basis differential [2]	July 2024 to Dec 2024	3,000 bbl/d	WTI less US$13.70/bbl	WCS
Basis differential	Jan 2024 to Dec 2024	1,500 bbl/d	WTI less US$2.65/bbl	MSW
Basis differential [2]	Apr 2024 to Dec 2024	1,250 bbl/d	WTI less US$3.40/bbl	MSW
Basis differential [2]	July 2024 to Dec 2024	2,500 bbl/d	WTI less US$2.85/bbl	MSW
Collar	Jan 2024 to Mar 2024	10,400 bbl/d	US$60.00/US$100.00	WTI
Collar	Jan 2024 to Jun 2024	24,500 bbl/d	US$60.00/US$100.00	WTI
Collar	July 2024 to Dec 2024	2,500 bbl/d	US$60.00/US$90.21	WTI
Collar	Apr 2024 to Jun 2024	11,750 bbl/d	US$60.00/US$100.00	WTI
Collar	July 2024 to Dec 2024	2,500 bbl/d	US$60.00/US$94.15	WTI
Collar	July 2024 to Dec 2024	10,000 bbl/d	US$60.00/US$100.00	WTI
Collar	July 2024 to Sep 2024	10,000 bbl/d	US$60.00/US$100.00	WTI
Collar	Oct 2024 to Dec 2024	2,500 bbl/d	US$60.00/US$100.00	WTI
Collar [2]	July 2024 to Dec 2024	9,000 bbl/d	US$60.00/US$84.58	WTI
Collar [2]	Oct 2024 to Dec 2024	7,000 bbl/d	US$60.00/US$86.43	WTI
Natural Gas				
Fixed Sell	Jan 2024 to Mar 2024	3,500 mmbtu/d	US$3.5025	NYMEX
Collar	Jan 2024 to Mar 2024	11,538 mmbtu/d	US$2.50/US$3.65	NYMEX
Collar	Apr 2024 to Jun 2024	11,538 mmbtu/d	US$2.33/US$3.00	NYMEX
Collar	Jan 2024 to Dec 2024	2,500 mmbtu/d	US$3.00/US$4.06	NYMEX
Collar	Jan 2024 to Dec 2024	2,500 mmbtu/d	US$3.00/US$4.09	NYMEX
Collar	Jan 2024 to Dec 2024	5,000 mmbtu/d	US$3.00/US$4.10	NYMEX
Collar	Jan 2024 to Dec 2024	8,500 mmbtu/d	US$3.00/US$4.15	NYMEX
Collar	Jan 2024 to Dec 2024	5,000 mmbtu/d	US$3.00/US$4.19	NYMEX
Natural Gas Liquids				
Fixed Sell	Jan 2024 to Mar 2024	34,364 gallon/d	US$0.2280/gallon	Mt. Belvieu Non-TET Ethane

(1) Based on the weighted average price per unit for the period.
(2) Contracts entered subsequent to December 31, 2023.

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, 2023 and 2022.

	Years Ended December 31					
	2023			2022		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**61,157**	**60,997**	**122,154**	55,275	28,245	83,519
Operating netback:						
Total sales, net of blending and other expense[(1)]	**$ 67.39**	**$ 74.27**	**$ 70.82**	$ 86.10	$ 93.36	$ 88.56
Less:						
Royalties [(2)]	**(9.55)**	**(20.51)**	**(15.02)**	(13.75)	(27.70)	(18.47)
Operating expense [(2)]	**(16.51)**	**(9.08)**	**(12.80)**	(16.25)	(9.19)	(13.86)
Transportation expense [(2)]	**(2.88)**	**(1.12)**	**(2.00)**	(2.41)	—	(1.59)
Operating netback [(1)]	**$ 38.45**	**$ 43.56**	**$ 41.00**	$ 53.69	$ 56.47	$ 54.64
Realized financial derivatives gain (loss) [(3)]	**—**	**—**	**0.81**	—	—	(10.97)
Operating netback after financial derivatives [(1)]	**$ 38.45**	**$ 43.56**	**$ 41.81**	$ 53.69	$ 56.47	$ 43.67

(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 or loss divided by barrels of oil equivalent production volume for the applicable period.

Our operating netback of $41.00/boe for 2023 was lower than $54.64/boe for 2022 due to lower benchmark pricing in Canada and the U.S. which resulted in a decrease in per unit sales net of royalties. Total operating expense and transportation expense of $14.80/boe was lower than $15.45/boe in 2022 which reflects lower operating and transportation costs on the operated Eagle Ford properties acquired from Ranger. Including realized gains on financial derivatives, our operating netback was $41.81/boe for 2023 compared to $43.67/boe for 2022.

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, 2023 and 2022.

	Years Ended December 31		
($ thousands except for per boe)	**2023**	2022	Change
Gross general and administrative expense	**$ 84,096**	$ 55,785	$ 28,311
Overhead recoveries	**(14,307)**	(5,515)	(8,792)
General and administrative expense	**$ 69,789**	$ 50,270	$ 19,519
General and administrative expense per boe [(1)]	**$ 1.57**	$ 1.65	$ (0.08)

(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 $69.8 million ($1.57/boe) for 2023 compared to $50.3 million ($1.65/boe) for 2022. G&A expense was $19.5 million higher relative to 2022 due to the increase in staffing levels and integration costs associated with the Merger with Ranger. G&A expense of $69.8 million ($1.57/boe) for 2023 was lower than our revised annual guidance of $80 million ($1.80/boe). We expect annual G&A expense of $92 million ($1.65/boe) for 2024 which reflects a full-year of staffing costs associated with the personnel retained after the acquisition of Ranger.

FINANCING AND INTEREST EXPENSE

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

The following table summarizes our financing and interest expense for the years ended December 31, 2023 and 2022.

	Years Ended December 31		
($ thousands except for per boe)	**2023**	2022	Change
Interest on credit facilities	**$ 56,713**	$ 19,550	$ 37,163
Interest on long-term notes	**102,426**	60,643	41,783
Interest on lease obligations	**684**	193	491
Cash interest	**$ 159,823**	$ 80,386	$ 79,437
Amortization of debt issue costs	**11,944**	6,286	5,658
Accretion of asset retirement obligations	**20,406**	15,683	4,723
Early redemption expense	**—**	2,462	(2,462)
Financing and interest expense	**$ 192,173**	$ 104,817	$ 87,356
Cash interest per boe[(1)]	**$ 3.58**	$ 2.64	$ 0.94
Financing and interest expense per boe[(1)]	**$ 4.31**	$ 3.44	$ 0.87

(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 $192.2 million ($4.31/boe) in 2023 compared to $104.8 million ($3.44/boe) in 2022. Higher interest costs in 2023 relative to 2022 are primarily a result of the additional debt outstanding after the Merger with Ranger.

Cash interest of $159.8 million ($3.58/boe) in 2023 was higher than $80.4 million ($2.64/boe) in 2022 as a result of additional debt outstanding in 2023 after the Merger which included the issuance of US$800.0 million aggregate principal amount of long-term notes. Interest on our credit facilities was higher in 2023 relative to 2022 due to the increase in applicable borrowing rates along with an increase in the principal amounts outstanding following the Merger. The weighted average interest rate applicable on our credit facilities was 7.6% in 2023 compared to 3.6% in 2022.

Accretion of asset retirement obligations of $20.4 million for 2023 was higher than $15.7 million for 2022 primarily due to higher discount rates in 2023 relative to 2022. Accretion of debt issues costs was higher in 2023 relative to 2022 due to the increase in debt issue costs associated with the expanded credit facilities and new long-term notes issued to fund the Merger with Ranger.

Cash interest of $159.8 million ($3.58/boe) for 2023 was consistent with our revised annual guidance of $156 million ($3.50/boe). We expect cash interest to be $190 million ($3.40/boe) for 2024.

EXPLORATION AND EVALUATION EXPENSE

Exploration and evaluation ("E&E") expense is related to the expiry of leases and the de-recognition of costs for exploration programs that have not demonstrated commercial viability and technical feasibility. E&E expense will vary depending on the timing of expiring leases, the accumulated costs of the expiring leases and the economic facts and circumstances related to the Company's exploration programs. Exploration and evaluation expense was $8.9 million for 2023 compared to $30.2 million for 2022.

DEPLETION AND DEPRECIATION

Depletion and depreciation expense varies with the carrying amount of the Company's oil and gas properties, the amount of proved and 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, 2023 and 2022.

	Years Ended December 31		
($ thousands except for per boe)	**2023**	2022	Change
Depletion and depreciation	**$ 1,047,904**	$ 587,050	$ 460,854
Depletion and depreciation per boe[(1)]	**$ 23.50**	$ 19.26	$ 4.24

(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 $1.0 billion ($23.50/boe) for 2023 compared to $587.1 million ($19.26/boe) for 2022. Total depletion and depreciation expense as well as the depletion and depreciation rate per boe were higher in 2023 relative to 2022 due to impairment reversals in Q4/2022 which increased the depletable base for our legacy assets in addition to depletion on the assets acquired from Ranger which have a higher depletion rate than our other properties.

IMPAIRMENT

2023 Impairment

At December 31, 2023, we identified indicators of impairment for oil and gas properties in our legacy non-operated Eagle Ford cash-generating unit ("CGU") due to changes in our reserves volumes and in our Viking CGU due to changes in reserves along with a loss recorded on disposition of an asset within the CGU. The recoverable amounts for the two CGUs were not sufficient to support their carrying values which resulted in an impairment of $833.7 million recorded at December 31, 2023.

At December 31, 2023, the recoverable amounts of the two CGUs were calculated using the following benchmark reference prices for the years 2024 to 2033 adjusted for commodity differentials specific to the CGU. The prices and costs subsequent to 2033 have been adjusted for inflation at an annual rate of 2.0%.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
WTI crude oil (US$/bbl)	73.67	74.98	76.14	77.66	79.22	80.80	82.42	84.06	85.74	87.46
LLS crude oil (US$/bbl)	76.49	77.80	78.95	80.35	81.95	83.59	85.27	86.97	88.71	90.48
Edmonton par oil ($/bbl)	92.91	95.04	96.07	97.99	99.95	101.94	103.98	106.06	108.18	110.35
NYMEX Henry Hub gas (US$/mmbtu)	2.75	3.64	4.02	4.10	4.18	4.27	4.35	4.44	4.53	4.62
AECO gas ($/mmbtu)	2.20	3.37	4.05	4.13	4.21	4.30	4.38	4.47	4.56	4.65
Exchange rate (CAD/USD)	0.75	0.75	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76

The following table summarizes the recoverable amount and impairment for each of the two CGUs at December 31, 2023 and demonstrates the sensitivity of the impairment to reasonably possible changes in key assumptions inherent in the calculation.

	Recoverable amount	Impairment loss	Change in discount rate of 1%	Change in oil price of $2.50/bbl	Change in gas price of $0.25/mcf
Viking CGU	$ 606,290	$ 184,000	$ 26,500	$ 53,000	$ 3,500
Eagle Ford Non-op CGU [(1)]	1,429,658	649,662	71,300	107,600	25,700

(1) There were no indicators of impairment identified for the Eagle Ford Operated CGU which includes the assets acquired from Ranger.

2022 Impairment Reversal

At December 31, 2022, indicators of impairment reversal were identified for oil and gas properties in five CGUs due to the increase in forecasted commodity prices in addition to changes in reserves volumes. The recoverable amount for three CGUs exceeded their carrying values which resulted in an impairment reversal of $245.2 million recorded at December 31, 2022. At December 31, 2022, we identified indicators of impairment reversal for E&E assets in the Peace River CGU due to an increase in land sale values and recorded an impairment reversal of $22.5 million. The total impairment reversal recorded at December 31, 2022 was $267.7 million.

The following table summarizes the recoverable amount and impairment reversal for each of the five CGUs at December 31, 2022 and demonstrates the sensitivity of the impairment reversal to reasonably possible changes in key assumptions inherent in the calculation.

	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 [(1)]	$ 119,031	$ 23,707	$ —	$ —	—
Peace River CGU [(1)]	676,939	140,534	—	—	—
Lloydminster CGU	449,250	—	11,500	53,000	—
Viking CGU	1,322,193	81,000	39,500	78,000	4,000
Eagle Ford Non-op CGU	2,102,646	—	95,800	131,100	28,500

(1) The impairment reversals for the Conventional and Peace River CGUs were limited to the total accumulated impairments less subsequent depletion of $23.7 million and $140.5 million, respectively. As a result, changes in the key assumptions presented in the table above have no impact on the amount of the impairment reversal as at December 31, 2022.

SHARE-BASED COMPENSATION EXPENSE

Share-based compensation ("SBC") expense includes expense associated with our Share Award Incentive Plan, Incentive Award Plan, and Deferred Share Unit Plan. SBC expense associated with equity-classified awards is recognized in net income or loss over the vesting period of the awards with a corresponding increase in contributed surplus. SBC expense associated with cash-settled awards is recognized in net income or loss over the vesting period of the awards, with a corresponding financial liability included in share-based compensation liability, and includes gains or losses on equity total return swaps. SBC expense varies with the quantity of unvested share awards outstanding and changes in the market price of our common shares.

We recorded SBC expense of $37.7 million for 2023 compared to $29.1 million for 2022. SBC expense for 2023 includes cash compensation expense of $21.5 million which is lower than $25.9 million for 2022. Lower cash SBC expense reflects a decrease in our share price during 2023 along with a reduction of the notional amount of equity return swaps outstanding in 2023 compared to 2022. SBC expense for 2023 also includes non-cash compensation expense of $16.2 million related to awards assumed in conjunction with the Merger which were settled in Baytex common shares.

Regular expensing of compensation awards is considered a cash expense as we intend to settle currently outstanding and future awards in cash while Baytex is repurchasing shares as part of its shareholder return program. In Q1/2023 we reduced the notional amount of the equity total return swaps to match the number of awards outstanding under the Deferred Share Unit Plan where we previously had targeted an amount equivalent to approximately 90-100% of all cash settled awards outstanding.

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 credit facilities in our Canadian functional currency entities. The long-term notes and credit facilities 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)	**2023**	2022	Change
Unrealized foreign exchange (gain) loss	**$ (14,300)**	$ 45,073	$ (59,373)
Realized foreign exchange loss (gain)	**3,452**	(1,632)	5,084
Foreign exchange (gain) loss	**$ (10,848)**	$ 43,441	$ (54,289)
CAD/USD exchange rates:			
At beginning of period	**1.3534**	1.2656	
At end of period	**1.3205**	1.3534	

We recorded a foreign exchange gain of $10.8 million for 2023 compared to a loss of $43.4 million for 2022.

The unrealized foreign exchange gain of $14.3 million for 2023 is primarily related to changes in the reported amount of our long-term notes and credit facilities. The gain recorded in 2023 is due to a strengthening of the Canadian dollar relative to U.S. dollar at December 31, 2023 compared to December 31, 2022 and June 20, 2023 when additional U.S. denominated debt was issued to fund the Merger with Ranger. The unrealized foreign exchange loss of $45.1 million for 2022 relates to a weakening of the Canadian dollar relative to the U.S. dollar at December 31, 2022 compared to December 31, 2021 and reflects the remeasurement of our long-term notes and credit facilities.

Realized foreign exchange gains and losses will fluctuate depending on the amount and timing of day-to-day U.S. dollar denominated transactions for our Canadian operations. We recorded a realized foreign exchange loss of $3.5 million for 2023 compared to a gain of $1.6 million for 2022.

INCOME TAXES

	Years Ended December 31		
($ thousands)	**2023**	2022	Change
Current income tax expense	**$ 14,403**	$ 3,594	$ 10,809
Deferred income tax (recovery) expense	**(297,629)**	31,716	(329,345)
Total income tax (recovery) expense	**$ (283,226)**	$ 35,310	$ (318,536)

Current income tax expense was $14.4 million for 2023 compared to $3.6 million recorded in 2022. Current income tax is higher in 2023 due to higher tax owed on our U.S. operations following the Merger with Ranger. We recorded a deferred income tax recovery of $297.6 million for 2023 compared to deferred tax expense of $31.7 million for 2022. The deferred tax recovery in 2023 is primarily related to the effects of the transaction structuring for the Merger in Q2/2023 along with the effects of impairment losses on our Canadian and U.S. assets in 2023.

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. Following objections and submissions, in November 2023 the CRA issued notices of confirmation regarding their prior reassessments. In February 2024, Baytex filed notices of appeal with the Tax Court of Canada and we estimate it could take between two and three years to receive a judgment. The reassessments do not require us to pay any amounts in order to participate in the appeals process. 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.

We remain confident that the tax filings of the affected entities are correct and will defend our tax filing positions. We have also purchased $272.5 million of insurance coverage for a premium of $50.3 million which will help manage the litigation risk associated with this matter. The most recent reassessments issued by the CRA assert taxes owing by the trusts of $244.8 million, late payment interest of $166.6 million as at the date of reassessments and a late filing penalty in respect of the 2011 tax year of $4.1 million.

By way of background, we acquired several privately held commercial trusts in 2010 with accumulated non-capital losses of $591.0 million (the "Losses"). The Losses were subsequently deducted in computing the taxable income of those trusts. The reassessments, as confirmed in November 2023, disallow the deduction of the Losses for two reasons. Firstly, the reassessments allege that (i) the trusts were resettled, and (ii) the resulting successor trusts were not able to access the losses of the predecessor trusts. Secondly, the reassessments allege that the general anti-avoidance rule of the Income Tax Act (Canada) operates to deny the deduction of the losses. If, after exhausting available appeals, the deduction of Losses continues to be disallowed, either the trusts or their corporate beneficiary will owe cash taxes, late payment interest and potentially penalties. The amount of cash taxes owing, late payment interest and potential penalties are dependent upon the taxpayer(s) ultimately liable (the trusts or their corporate beneficiary) and the amount of unused tax shelter available to those/that taxpayer(s) to offset the reassessed income, including tax shelter from future years that may be carried back and applied to prior years.

The following table summarizes our Canadian and Foreign tax pools.

Canadian Tax Pools *($ thousands)*	**December 31, 2023**	December 31, 2022
Canadian oil and natural gas property expenditures	**$ 203,406**	$ 355,028
Canadian development expenditures	**518,788**	483,270
Undepreciated capital costs	**280,564**	275,987
Non-capital losses	**643,697**	818,326
Financing costs and other	**98,816**	62,442
Total Canadian tax pools	**$ 1,745,271**	$ 1,995,053
Foreign Tax Pools *($ thousands)*		
Depletion	**1,893,577**	139,013
Intangible drilling costs	**352,021**	$ —
Tangibles	**213,372**	14,483
Net operating losses	**2,558,472**	813,753
Other	**468,554**	96,157
Total Foreign tax pools	**$ 5,485,996**	$ 1,063,406

NET (LOSS) INCOME AND ADJUSTED FUNDS FLOW

The components of adjusted funds flow and net income or loss for the years ended December 31, 2023 and 2022 are set forth in the following table.

	Years Ended December 31		
($ thousands)	**2023**	2022	Change
Petroleum and natural gas sales	**$ 3,382,621**	$ 2,889,045	$ 493,576
Royalties	**(669,792)**	(562,964)	(106,828)
Revenue, net of royalties	**2,712,829**	2,326,081	386,748
Expenses			
Operating	**(570,839)**	(422,666)	(148,173)
Transportation	**(89,306)**	(48,561)	(40,745)
Blending and other	**(224,802)**	(189,454)	(35,348)
Operating netback [(1)]	**$ 1,827,882**	$ 1,665,400	$ 162,482
General and administrative	**(69,789)**	(50,270)	(19,519)
Cash interest	**(159,823)**	(80,386)	(79,437)
Realized financial derivatives gain (loss)	**36,212**	(334,481)	370,693
Realized foreign exchange (loss) gain	**(3,452)**	1,632	(5,084)
Other expense	**(815)**	(7,253)	6,438
Current income tax expense	**(14,403)**	(3,594)	(10,809)
Cash share-based compensation	**(21,462)**	(25,897)	4,435
Adjusted funds flow [(2)]	**$ 1,594,350**	$ 1,165,151	$ 429,199
Transaction costs	**(49,045)**	—	(49,045)
Exploration and evaluation	**(8,896)**	(30,239)	21,343
Depletion and depreciation	**(1,047,904)**	(587,050)	(460,854)
Non-cash share-based compensation	**(16,237)**	(3,159)	(13,078)
Non-cash financing and interest	**(32,350)**	(24,431)	(7,919)
Non-cash other income	**1,271**	4,009	(2,738)
Unrealized financial derivatives (loss) gain	**(11,517)**	135,471	(146,988)
Unrealized foreign exchange gain (loss)	**14,300**	(45,073)	59,373
(Loss) gain on dispositions	**(141,295)**	4,898	(146,193)
Impairment (loss) reversal	**(833,662)**	267,744	(1,101,406)
Deferred income tax recovery (expense)	**297,629**	(31,716)	329,345
Net (loss) income	**$ (233,356)**	$ 855,605	$ (1,088,961)

(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 $1.6 billion for 2023 compared to $1.2 billion for 2022. The $429.2 million increase in adjusted funds flow for 2023 is due to higher production from the Merger with Ranger which was partially offset by lower commodity prices and also resulted in a $370.7 million improvement in realized gains (losses) on financial derivatives.

We reported net loss of $233.4 million for 2023 compared to net income of $855.6 million for 2022. The decrease in net income for 2023 relative to 2022 is primarily a result of the $833.7 million impairment loss recorded in 2023 compared to the $267.7 million impairment reversal recorded in 2022 and a $460.9 million increase in depletion and depreciation expense as a result of the oil and gas properties acquired from Ranger. The decrease in net income was partially offset by a $329.3 million decrease in deferred income tax expense primarily related to the effects of the transaction structuring for the Merger.

OTHER COMPREHENSIVE (LOSS) INCOME

Other comprehensive (loss) income is comprised of the foreign currency translation adjustment on U.S. net assets which is not recognized in net income or loss. The foreign currency translation loss of $65.3 million for 2023 relates to the change in value of our U.S. net assets and is due to the strengthening of the Canadian dollar relative to the U.S. dollar at December 31, 2023 compared to December 31, 2022 and June 20, 2023 when we completed the Merger with Ranger. The CAD/USD exchange rate was 1.3205 CAD/USD at December 31, 2023 compared to 1.32485 CAD/USD at June 20, 2023 and 1.3534 CAD/USD at December 31, 2022.

CAPITAL EXPENDITURES

Capital expenditures for the years ended December 31, 2023 and 2022 are summarized as follows.

	Years Ended December 31					
	2023			2022		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 393,127**	**$ 492,030**	**$ 885,157**	$ 321,836	$ 136,746	$ 458,582
Facilities	**46,225**	**42,167**	**88,392**	32,573	3,151	35,724
Land, seismic and other	**23,846**	**15,392**	**39,238**	26,393	843	27,236
Exploration and development expenditures	**$ 463,198**	**$ 549,589**	**$ 1,012,787**	$ 380,802	$ 140,740	$ 521,542
Property acquisitions	**20,023**	**18,891**	**38,914**	1,352	—	1,352
Proceeds from dispositions	**$ (160,256)**	**$ —**	**$ (160,256)**	$ (25,649)	$ —	$ (25,649)

Exploration and development expenditures were $1.0 billion for 2023 compared to $521.5 million for 2022. Exploration and development expenditures for 2023 reflect increased development activity in Canada along with development activity on the properties acquired from Ranger after the Merger closed on June 20, 2023.

In Canada, exploration and development expenditures were $463.2 million in 2023 which is $82.4 million higher than $380.8 million in 2022. Drilling and completion spending of $393.1 million in 2023 reflects higher light and heavy oil development activity relative to 2022 when we spent $321.8 million. We also invested $46.2 million on facilities, $23.8 million on land, seismic and other expenditures and completed a non-core property disposition of certain Viking assets for proceeds of $159.7 million, including closing adjustments.

Total U.S. exploration and development expenditures were $549.6 million for 2023 which is $408.8 million higher than $140.7 million for 2022. Exploration and development activity for 2023 reflects expenditures for development activity on our operated properties after closing of the Merger on June 20, 2023 along with additional activity on our non-operated properties in the Eagle Ford.

Total exploration and development expenditures of $1.0 billion for 2023 were consistent with our revised annual guidance of approximately $1.0 billion. We expect annual exploration and development expenditures of $1.2 - $1.3 billion for 2024.

CAPITAL RESOURCES AND LIQUIDITY

Our capital management objective is to maintain a strong balance sheet that provides financial flexibility to execute our development programs, provide returns to shareholders and optimize our portfolio through strategic acquisitions. We strive to actively manage our capital structure in response to changes in economic conditions. At December 31, 2023, our capital structure was comprised of shareholders' capital, long-term notes, trade receivables, prepaids and other assets, trade payables, dividends payable, share-based compensation liability, other long-term liabilities, cash 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.

We are committed to maintaining a strong balance sheet. Upon reaching a total debt[1] target of $1.5 billion we intend to direct 75% of free cash flow[2] to shareholder returns. At December 31, 2023, net debt[3] of $2.5 billion was $1.5 billion higher than $1.0 billion at December 31, 2022. The increase in net debt for 2023 is primarily due to $732.8 million of cash consideration paid and the assumption of $1.1 billion of net debt assumed in conjunction with the Merger. The cash portion of the transaction was funded with Baytex's expanded US$1.1 billion credit facility, a US$150 million two-year term loan facility which was repaid in August 2023 along with the net proceeds from the issuance of US$800 million senior unsecured notes due 2030. Baytex closed the US$800 million principal amount senior unsecured note offering on April 27, 2023 with the proceeds released from escrow at completion of the Merger. As of December 31, 2023 we have reduced net debt by $280.6 million since closing the Merger on June 20, 2023.

In June 2023, we renewed our normal course issuer bid ("NCIB") and began repurchasing our common shares in July 2023 as part of our shareholder return framework. As of December 31, 2023, we repurchased 40.5 million common shares at an average price of $5.48 per share for total consideration of $221.9 million.

Our shareholder returns framework includes a quarterly dividend. On October 2, 2023 and January 2, 2024, we paid a quarterly cash dividend of CDN$0.0225 per share to shareholders of record. On February 28, 2024, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on April 1, 2024 for shareholders on record as at March 15, 2024. These dividends are designated as "eligible dividends" for Canadian income tax purposes. For U.S. income tax purposes, Baytex's dividends are considered "qualified dividends."

(1) Calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.com.
(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 for further information.
(3) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

Credit Facilities

At December 31, 2023, we had $864.7 million of principal amount outstanding under our revolving credit facilities which total US$1.1 billion ($1.5 billion) (the "Credit Facilities").

On June 20, 2023, we amended our Credit Facilities to facilitate the cash consideration paid in conjunction with the Merger and to assume Ranger's net debt. The Credit Facilities were increased to US$1.1 billion and mature on April 1, 2026. The Credit Facilities are secured and are comprised of a US$50 million operating loan and a US$750 million syndicated revolving loan for Baytex and a US$45 million operating loan and a US$255 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc.

There are no mandatory principal payments required prior to maturity which could be extended upon our request. The Credit Facilities contain standard commercial covenants in addition to the financial covenants detailed below. Advances under the Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank's prime lending rate, bankers' acceptance discount rates or secured overnight financing rates ("SOFR"), plus applicable margins.

The weighted average interest rate on the Credit Facilities was 7.6% for 2023 as compared to 3.6% for 2022. The interest rate on our Credit Facilities has increased due to an increase in the margins applicable to our Credit Facilities along with higher government benchmark rates in 2023 relative to 2022.

As at December 31, 2023, Baytex had $5.6 million of outstanding letters of credit, $4.7 million of which is under a $20 million uncommitted unsecured demand revolving letter of credit facility (December 31, 2022 - $15.7 million outstanding). Letters of credit under this facility are guaranteed by Export Development Canada and do not use capacity available under the Credit Facilities.

The agreements and associated amending agreements relating to the Credit Facilities are accessible on the SEDAR+ website at www.sedarplus.com and through the U.S. Securities and Exchange Commission at www.sec.gov.

Financial Covenants

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at December 31, 2023.

Covenant Description	Position as at December 31, 2023	Covenant
Senior Secured Debt [1] to Bank EBITDA [2] (Maximum Ratio)	**0.4:1.0**	3.5:1.0
Interest Coverage [3] (Minimum Ratio)	**11.3:1.0**	3.5:1.0
Total Debt [4] to Bank EBITDA [2] (Maximum Ratio)	**1.1:1.0**	4.0:1.0

(1) "Senior Secured Debt" is calculated in accordance with the credit facility agreement and is defined as the principal amount of the credit facilities and other secured obligations identified in the credit facility agreement. As at December 31, 2023, the Company's Senior Secured Debt totaled $864.7 million.

(2) "Bank EBITDA" is calculated based on terms and definitions set out in the credit facility 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, 2023 was $2.2 billion.

(3) "Interest coverage" is calculated in accordance with the credit facility 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, 2023 were $195.2 million.

(4) "Total Debt" is calculated in accordance with the credit facility agreement and is defined as all obligations, liabilities, and indebtedness of Baytex excluding trade payables, other long-term liabilities, dividends payable, share-based compensation liability, asset retirement obligations, leases, deferred income tax liabilities, and financial derivative liabilities. At December 31, 2023 our Total Debt was $2.5 billion.

Long-Term Notes

We have two issuances of long-term notes outstanding with a total principal amount of $1.6 billion as at December 31, 2023. The long-term notes do not contain any financial maintenance covenants.

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. At December 31, 2023 there was US$409.8 million aggregate principal amount of the 8.75% Senior Notes outstanding.

On April 27, 2023, we issued US$800 million aggregate principal amount of senior unsecured notes due April 30, 2030 bearing interest at a rate of 8.50% per annum semi-annually (the "8.50% Senior Notes"). The 8.50% Senior Notes were issued at 98.709% of par and are redeemable at our option, in whole or in part, at specified redemption prices after April 30, 2026 and will be redeemable at par from April 30, 2028 to maturity. Net proceeds of $1.0 billion reflects $13.7 million for the original issue discount and transaction costs of $18.5 million incurred with the issuance.

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, 2023, we issued 311.4 million common shares on closing of the Merger with Ranger in addition to 5.9 million common shares to settle awards outstanding in conjunction with the Merger. As at February 28, 2024, we had 821.7 million common shares issued and outstanding and no preferred shares issued and outstanding.

Contractual Obligations

We have a number of financial obligations that are incurred in the ordinary course of business. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of December 31, 2023 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
Credit Facilities - principal	**$ 864,736**	$ —	$ 864,736	$ —	$ —
Long-term notes - principal	**1,597,475**	—	—	541,114	1,056,361
Interest on long-term notes [1]	**722,732**	137,138	274,276	191,515	119,803
Lease obligations - principal [2]	**37,553**	15,722	10,415	7,128	4,288
Processing agreements	**5,642**	618	1,003	563	3,458
Transportation agreements	**212,400**	52,691	94,866	47,601	17,242
Total	**$ 3,440,538**	$ 206,169	$ 1,245,296	$ 787,921	$ 1,201,152

(1) 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.

(2) Includes leases which are committed to that have not yet commenced as at December 31, 2023.

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. The present value of the future estimated abandonment and reclamation costs are included in the asset retirement obligations presented in the statement of financial position. 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					
	2023			2022		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total daily production						
Light oil and condensate (bbl/d)	**14,143**	**55,981**	**70,124**	14,511	17,594	32,105
Heavy oil (bbl/d)	**39,569**	**—**	**39,569**	32,819	—	32,819
NGL (bbl/d)	**2,937**	**20,223**	**23,160**	1,958	5,703	7,661
Total liquids (bbl/d)	**56,649**	**76,204**	**132,853**	49,288	23,297	72,585
Natural gas (mcf/d)	**48,573**	**116,548**	**165,121**	45,953	39,726	85,679
Total production (boe/d)	**64,744**	**95,629**	**160,373**	56,946	29,918	86,864
Operating netback ($/boe)						
Light oil and condensate ($/bbl) [1]	**$ 99.93**	**$ 105.83**	**$ 104.64**	$ 108.21	$ 114.64	$ 111.73
Heavy oil, net of blending and other expense ($/bbl) [2]	**62.48**	**—**	**62.48**	64.06	—	64.06
NGL ($/bbl) [1]	**27.38**	**26.68**	**26.76**	39.68	38.36	38.70
Natural gas ($/mcf) [1]	**2.40**	**3.07**	**2.87**	5.38	6.93	6.10
Total sales, net of blending and other per boe [2]	**63.06**	**71.34**	**68.00**	70.20	83.94	74.93
Royalties per boe [3]	**(9.69)**	**(19.42)**	**(15.49)**	(10.06)	(25.06)	(15.23)
Operating expense per boe [3]	**(15.61)**	**(8.17)**	**(11.17)**	(15.98)	(7.48)	(13.06)
Transportation expense per boe [3]	**(3.02)**	**(1.33)**	**(2.02)**	(2.83)	—	(1.85)
Operating netback per boe [2]	**$ 34.74**	**$ 42.42**	**$ 39.32**	$ 41.33	$ 51.40	$ 44.79
Financial						
Petroleum and natural gas sales	**$ 437,889**	**$ 627,626**	**$ 1,065,515**	$ 417,952	$ 231,034	$ 648,986
Royalties	**(57,746)**	**(170,824)**	**(228,570)**	(52,718)	(68,973)	(121,691)
Revenue, net of royalties	**380,143**	**456,802**	**836,945**	365,234	162,061	527,295
Operating	**(93,006)**	**(71,867)**	**(164,873)**	(83,742)	(20,593)	(104,335)
Transportation	**(18,005)**	**(11,739)**	**(29,744)**	(14,817)	—	(14,817)
Blending and other	**(62,296)**	**—**	**(62,296)**	(50,174)	—	(50,174)
Operating netback [2]	**$ 206,836**	**$ 373,196**	**$ 580,032**	$ 216,501	$ 141,468	$ 357,969
General and administrative	**—**	**—**	**(22,280)**	—	—	(14,945)
Cash interest	**—**	**—**	**(56,698)**	—	—	(19,711)
Realized financial derivatives gain (loss)	**—**	**—**	**12,377**	—	—	(49,665)
Other	**—**	**—**	**(11,283)**	—	—	(18,096)
Adjusted funds flow [4]	**$ 206,836**	**$ 373,196**	**$ 502,148**	$ 216,501	$ 141,468	$ 255,552
Net (loss) income	**$ (255,238)**	**$ (531,505)**	**$ (625,830)**	$ 366,104	$ 88,480	$ 352,807
Exploration and development expenditures	**$ 75,137**	**$ 124,077**	**$ 199,214**	$ 85,641	$ 17,993	$ 103,634
Property acquisitions	**15,032**	**18,891**	**33,923**	1,085	—	1,085
Proceeds from dispositions	**$ (159,745)**	**$ —**	**$ (159,745)**	$ (148)	$ —	$ (148)
Net debt [4]			**$ 2,534,287**			987,446

(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 expense, operating expense 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		
	2023	2022	Change
Benchmark Averages			
WTI oil (US$/bbl) [(1)]	**78.32**	82.64	(4.32)
MEH oil (US$/bbl) [(2)]	**80.62**	85.88	(5.26)
MEH oil differential to WTI (US$/bbl)	**2.30**	3.24	(0.94)
Edmonton par oil ($/bbl) [(3)]	**99.72**	109.57	(9.85)
Edmonton par oil differential to WTI (US$/bbl)	**(5.10)**	(1.94)	(3.16)
WCS heavy oil ($/bbl) [(4)]	**76.86**	77.37	(0.51)
WCS heavy oil differential to WTI (US$/bbl)	**(21.88)**	(25.65)	3.77
AECO natural gas price ($/mcf) [(5)]	**2.66**	5.58	(2.92)
NYMEX natural gas price (US$/mmbtu) [(6)]	**2.88**	6.26	(3.38)
CAD/USD average exchange rate	**1.3619**	1.3577	0.0042

(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 Q4/2023 reflect the successful execution of our 2023 development programs in the U.S. and Canada. We invested $199.2 million on exploration and development expenditures in Q4/2023 and delivered production of 160,373 boe/d. Free cash flow[(1)] was $290.8 million in Q4/2023 which reflects the disciplined execution of our development programs.

In Canada, production averaged 64,744 boe/d in Q4/2023 which was 7,798 boe/d higher than 56,946 boe/d reported for Q4/2022 as a result of our successful Clearwater development program at Peavine and our light oil Duvernay development. Lower benchmark pricing resulted in a realized price of $63.06/boe for Q4/2023 which was $7.14/boe lower than $70.20/boe for Q4/2022. The Edmonton Par benchmark averaged $99.72/bbl for Q4/2023 compared to $109.57/bbl for Q4/2022 and the WCS heavy oil benchmark was $76.86/bbl in Q4/2023 compared to $77.37/bbl for the same period of 2022. Lower commodity prices were the main factor that resulted in an operating netback[(1)] of $206.8 million ($34.74/boe) for Q4/2023 which was $9.7 million ($6.60/boe) lower than $216.5 million ($41.33/boe) reported for Q4/2022. Exploration and development expenditures were $75.1 million in Q4/2023 compared to $85.6 million in Q4/2022.

In the U.S., production averaged 95,629 boe/d for Q4/2023 which is 65,711 boe/d higher than 29,918 boe/d reported for Q4/2022 reflecting the production contribution from the Merger with Ranger. The MEH benchmark averaged US$80.62/bbl in Q4/2023 which was US$5.26/boe lower than US$85.88/bbl during Q4/2022 and resulted in a realized price of $71.34/boe which was $12.60/boe lower than our realized price of $83.94/boe in Q4/2022. Operating netback of $373.2 million ($42.42/boe) was $231.7 million ($8.98/boe) higher than $141.5 million ($51.40/boe) for Q4/2022 which reflects lower benchmark commodity prices and the additional production following the acquisition of operated Eagle Ford properties as part of the Merger. Activity on the acquired lands resulted in exploration and development expenditures of $124.1 million in Q4/2023 which were higher compared to Q4/2022 when we spent $18.0 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.

We generated adjusted funds flow[1] of $502.1 million in Q4/2023 which is $246.6 million higher than $255.6 million in Q4/2022. The increase in adjusted funds flow for Q4/2023 reflects higher production after the acquisition of operated Eagle Ford properties as part of the Merger with Ranger along with lower commodity prices relative to Q4/2022. The production contribution from the properties acquired from Ranger was the primary factor for the increase in production of 160,373 boe/d in Q4/2023 compared to 86,864 boe/d for Q4/2022. Higher production resulted in an operating netback[2] of $580.0 million for Q4/2023 which was $222.1 million higher than the same period of 2022 despite lower commodity prices that resulted in operating netback[2] of $39.32/boe for Q4/2023 which was $5.47/boe lower than $44.79/boe in Q4/2022. We recorded realized financial derivatives gains of $12.4 million in Q4/2023 compared to losses of $49.7 million in Q4/2022. G&A expense of $22.3 million in Q4/2023 was higher than $14.9 million in Q4/2022 due to additional administrative costs and staff retention required for the operation of the properties acquired from Ranger. Interest expense of $56.7 million in Q4/2023 was $37.0 million higher than $19.7 million for Q4/2022 which reflects the additional debt outstanding as a result of the Merger with Ranger in addition to an increase in interest rates during 2023. Net debt[1] was $2.5 billion at Q4/2023 compared to $1.0 billion in Q4/2022.

We recorded a net loss of $625.8 million in Q4/2023 compared to net income of $352.8 million in Q4/2022. The decrease in net income for Q4/2023 relative to Q4/2022 is primarily a result of the $833.7 million impairment loss recorded in Q4/2023 due to changes in reserves volumes and the loss on a disposition within the Viking CGU, compared to $267.7 million of impairment reversals recorded in Q4/2022, as well as an increase in depletion and depreciation expense as a result of the oil and gas properties acquired from Ranger.

(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.

QUARTERLY FINANCIAL INFORMATION

	2023				2022			
($ thousands, except per common share amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Petroleum and natural gas sales	**1,065,515**	1,163,010	598,760	555,336	648,986	712,065	854,169	673,825
Net (loss) income	**(625,830)**	127,430	213,603	51,441	352,807	264,968	180,972	56,858
Per common share - basic	**(0.75)**	0.15	0.37	0.09	0.65	0.48	0.32	0.10
Per common share - diluted	**(0.75)**	0.15	0.36	0.09	0.64	0.47	0.32	0.10
Adjusted funds flow [1]	**502,148**	581,623	273,590	236,989	255,552	284,288	345,704	279,607
Per common share - basic	**0.60**	0.68	0.47	0.43	0.47	0.51	0.61	0.49
Per common share - diluted	**0.60**	0.68	0.47	0.43	0.46	0.51	0.60	0.49
Free cash flow [2]	**290,785**	158,440	96,313	(1,918)	143,324	111,568	245,316	121,318
Per common share - basic	**0.35**	0.19	0.17	—	0.26	0.20	0.43	0.21
Per common share - diluted	**0.35**	0.18	0.16	—	0.26	0.20	0.43	0.21
Cash flows from operating activities	**474,452**	444,033	192,308	184,938	303,441	310,423	360,034	198,974
Per common share - basic	**0.57**	0.52	0.33	0.34	0.56	0.56	0.63	0.35
Per common share - diluted	**0.57**	0.52	0.33	0.34	0.55	0.56	0.63	0.35
Dividends declared	**18,381**	19,138	—	—	—	—	—	—
Per common share – basic	**0.02**	0.02	—	—	—	—	—	—
Per common share – diluted	**0.02**	0.02	—	—	—	—	—	—
Exploration and development expenditures	**199,214**	409,191	170,704	233,626	103,634	167,453	96,633	153,822
Canada	**75,137**	107,053	96,403	184,606	85,641	117,150	51,881	126,130
U.S.	**124,077**	302,138	74,301	49,020	17,993	50,303	44,752	27,692
Property acquisitions	**33,923**	4,277	(62)	506	1,085	—	208	59
Proceeds from dispositions	**(159,745)**	(226)	(50)	(235)	(148)	(25,460)	(14)	(27)
Net debt [1]	**2,534,287**	2,824,348	2,814,844	995,170	987,446	1,113,559	1,123,297	1,275,680
Total assets [3]	**7,460,931**	8,946,181	8,617,444	5,180,059	5,103,769	4,923,617	4,870,432	4,917,811
Common shares outstanding	**821,681**	845,360	862,192	545,553	544,930	547,615	560,139	569,214
Daily production								
Total production (boe/d)	**160,373**	150,600	89,761	86,760	86,864	83,194	83,090	80,867
Canada (boe/d)	**64,744**	63,289	55,874	60,651	56,946	55,803	54,919	53,385
U.S. (boe/d)	**95,629**	87,311	33,887	26,109	29,918	27,391	28,170	27,482
Benchmark prices								
WTI oil (US$/bbl)	**78.32**	82.26	73.78	76.13	82.64	91.56	108.41	94.29
WCS heavy ($/bbl)	**76.86**	93.02	78.85	69.44	77.37	93.62	122.05	100.99
Edmonton Light ($/bbl)	**99.72**	107.93	95.13	99.04	109.57	116.79	137.79	115.66
CAD/USD avg exchange rate	**1.3619**	1.3410	1.3431	1.3520	1.3577	1.3059	1.2766	1.2661
AECO gas ($/mcf)	**2.66**	2.39	2.35	4.34	5.58	5.81	6.27	4.59
NYMEX gas (US$/mmbtu)	**2.88**	2.55	2.10	3.42	6.26	8.20	7.17	4.95
Total sales, net of blending and other expense ($/boe) [2]	**68.00**	80.34	66.82	63.48	74.93	87.68	105.44	86.89
Royalties ($/boe) [4]	**(15.49)**	(17.33)	(13.21)	(11.94)	(15.23)	(19.21)	(22.69)	(16.86)
Operating expense ($/boe) [4]	**(11.17)**	(12.57)	(14.62)	(14.40)	(13.06)	(14.39)	(14.21)	(13.85)
Transportation expense ($/boe) [4]	**(2.02)**	(2.02)	(1.78)	(2.18)	(1.85)	(1.67)	(1.56)	(1.27)
Operating netback ($/boe) [2]	**39.32**	48.42	37.21	34.96	44.79	52.41	66.98	54.91
Financial derivatives gain (loss) ($/boe) [4]	**0.84**	0.15	2.00	0.69	(6.21)	(9.98)	(16.41)	(11.59)
Operating netback after financial derivatives ($/boe) [2]	**40.16**	48.57	39.21	35.65	38.58	42.43	50.57	43.32

(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) Previously disclosed amounts have been revised to conform with current period presentation.
(4) Calculated as royalties expense, operating expenses, transportation expense or financial derivatives gain or loss 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 capital programs while oil and natural gas prices have fluctuated. Production steadily increased from 80,867 boe/d in Q1/2022 to 160,373 boe/d in Q4/2023 which reflects strong well performance from our development programs in Canada and the U.S. along with the production contribution from the Merger with Ranger which closed on June 20, 2023.

Commodity prices strengthened to multi-year highs in 2022 following Russia's invasion of Ukraine which created elevated uncertainty surrounding the global supply of oil and natural gas. The impact of increased commodity prices is reflected in our realized price of $105.44/boe for Q2/2022 which is our strongest realized pricing in the most recent eight quarters. Our Q4/2023 realized price of $68.00/boe reflects recent declines in crude oil prices as global supply growth has resulted in a more balanced market.

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)] of $502.1 million for Q4/2023 reflects strong production results from our development plans in the U.S. and Canada in addition to the Merger partially offset by declining price realizations.

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. The increase in net debt[(1)] from $1.3 billion at Q1/2022 to $2.5 billion at Q4/2023 is primarily a result of the Merger which closed in Q2/2023 along with $418.4 million of shareholder returns. Since closing the Merger in Q2/2023 we have reduced net debt by $280.6 million which demonstrates our priority to maintain a strong balance sheet. The change in net debt also reflects free cash flow[(2)] of $1.2 billion generated over the last eight quarters.

(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 for 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

In June 2023, the International Sustainability Standards Board ("ISSB") issued IFRS S1 *General Requirements for Disclosure of Sustainability-related Financial Information* and IFRS S2 *Climate-related Disclosures* which are effective for annual reporting periods beginning on or after January 1, 2024. These standards provide for transition relief in IFRS S1 that allow reporting entity to report on only climate-related risks and opportunities in the first year of reporting under the sustainability standards.

The Canadian Securities Administrators ("CSA") are responsible for determining the reporting requirements for public companies in Canada and are responsible for decisions related to the adoption of the sustainability disclosure standard, including the effective annual reporting dates. The CSA issued proposed National Instrument *NI-51-107 – Disclosure of Climate-related Matters* in October 2021. The CSA intends to consider the ISSB standards in addition to developments in United States reporting requirements in its decision relating to development of climate-related disclosure requirements for Canadian reporting issuers. The CSA will involve the Canadian Sustainability Standards Board ("CSSB") for a combined review of the suitability of the adopting the ISSB standards in Canada. There is no requirement for public companies in Canada to adopt the ISSB standards until the CSA and CSSB have issued a decision on reporting requirements in Canada. While we are actively reviewing the ISSB standards we have not yet determined the impact on future financial statements nor have we quantified the costs to comply with such standards.

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at December 31, 2023, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets, liabilities, revenues and expenses. These judgments, estimates and assumptions are based on all relevant information available, including considerations related to various regulatory and legislative requirements, to the Company at the time of financial statement preparation. Actual results could be materially different from those estimates as the effect of future events cannot be determined with certainty. Revisions to estimates are recognized prospectively. 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 recoverable 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 qualified reserves evaluators and represent the estimated recoverable quantities of oil, natural gas and NGL reserves and the related 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 reserves and the related cash flows are based on a number of factors and assumptions. Changes to estimates and assumptions such as forecasted commodity prices, production volumes, capital and operating costs and royalty obligations could have a significant impact on reported reserves. Other estimates include ultimate reserve recovery, marketability of oil and natural gas and other geological, economic and technical factors. Changes in the Company's reserves estimates can have a significant impact on the calculation of depletion, the recoverability of deferred income tax assets and in the determination of recoverable value estimates for non-financial assets.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting when the assets acquired meet the definition of a business in accordance with IFRS. The determination of the fair value assigned to assets acquired and liabilities assumed requires management to make assumptions and estimates. These assumptions or estimates used in determining the fair value of assets acquired and liabilities assumed could impact the amounts assigned to assets, liabilities and goodwill. The determination of the acquisition-date fair value measurement of oil and gas properties acquired represents the largest fair value estimate which is derived from the present value of expected cash flows associated with estimated acquired proved and probable oil and gas reserves prepared by an independent qualified reserve evaluator using assumptions as outlined under "reserves", on an after-tax basis and applying a discount rate. Assumptions used to arrive at the fair value of oil and gas properties are further verified by way of market comparisons and third party sources.

Cash-generating Units

The Company's oil and gas properties are aggregated into CGUs which are the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows 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. These indicators can be internal such as changes in estimated proved and probable oil and gas reserves ("CGU reserves") and internally estimated oil and gas resources, or external such as market conditions impacting discount rates or market capitalization. The assessment for each CGU considers significant changes in the forecasted cash flows including reservoir performance, the number of development locations and timing of development, forecasted commodity prices, production volumes, capital and operating costs and royalty obligations.

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 and probable oil and gas reserves and the discount rate used to present value future cash flows. Any changes to these estimates and assumptions could impact the calculation of the recoverable amount and the carrying value of assets.

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 risk-free discount rates and inflation rates. The Company uses risk-free discount 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.

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.

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" and "net debt" 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 and heavy oil, net of blending and other expense

Total sales, net of blending and other expense and heavy oil, net of blending and other expense represent the total revenues and heavy oil revenues realized from produced volumes during a period, respectively. Total sales, net of blending and other expense is comprised of total petroleum and natural gas sales adjusted for blending and other expense. Heavy oil, net of blending and other expense is calculated as heavy oil sales less 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.

The following table reconciles heavy oil, net of blending and other expense to amounts disclosed in the primary financial statements in the following table.

	Three Months Ended			Years Ended December 31	
($ thousands)	**December 31, 2023**	September 30, 2023	December 31, 2022	**2023**	2022
Petroleum and natural gas sales	**$ 1,065,515**	$ 1,163,010	$ 648,986	**$ 3,382,621**	$ 2,889,045
Light oil and condensate [1]	**(675,072)**	(756,779)	(330,016)	**(2,029,123)**	(1,470,549)
NGL [1]	**(57,027)**	(46,972)	(27,276)	**(145,997)**	(120,505)
Natural gas sales [1]	**(43,674)**	(35,987)	(48,116)	**(125,952)**	(195,915)
Heavy oil sales	**$ 289,742**	$ 323,272	$ 243,578	**$ 1,081,549**	$ 1,102,076
Blending and other expense - heavy oil [2]	**(62,296)**	(49,830)	(50,174)	**(224,802)**	(189,454)
Heavy oil, net of blending and other expense	**$ 227,446**	$ 273,442	$ 193,404	**$ 856,747**	$ 912,622

(1) Component of petroleum and natural gas sales; see Note 14 Petroleum and Natural Gas Sales in the Consolidated Financial Statements for the year ended December 31, 2023 for further information.
(2) The portion of blending and other expense that relates to heavy oil sales for the applicable period.

Operating netback

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

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

	Three Months Ended			Years Ended December 31	
($ thousands)	**December 31, 2023**	September 30, 2023	December 31, 2022	**2023**	2022
Petroleum and natural gas sales	**$ 1,065,515**	$ 1,163,010	$ 648,986	**$ 3,382,621**	$ 2,889,045
Blending and other expense	**(62,296)**	(49,830)	(50,174)	**(224,802)**	(189,454)
Total sales, net of blending and other expense	**$ 1,003,219**	$ 1,113,180	$ 598,812	**$ 3,157,819**	$ 2,699,591
Royalties	**(228,570)**	(240,049)	(121,691)	**(669,792)**	(562,964)
Operating expense	**(164,873)**	(174,119)	(104,335)	**(570,839)**	(422,666)
Transportation expense	**(29,744)**	(27,983)	(14,817)	**(89,306)**	(48,561)
Operating netback	**$ 580,032**	$ 671,029	$ 357,969	**$ 1,827,882**	$ 1,665,400
Realized financial derivatives gain (loss) [(1)]	**12,377**	2,055	(49,665)	**36,212**	(334,481)
Operating netback after realized financial derivatives	**$ 592,409**	$ 673,084	$ 308,304	**$ 1,864,094**	$ 1,330,919

(1) Realized financial derivatives gain or loss is a component of financial derivatives gain or loss; see Note 18 Financial Instruments and Risk Management in the Consolidated Financial Statements for the year ended December 31, 2023 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, payments on lease obligations, transaction costs, and cash premiums on derivatives.

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

	Three Months Ended			Years Ended December 31	
($ thousands)	**December 31, 2023**	September 30, 2023	December 31, 2022	**2023**	2022
Cash flow from operating activities	**$ 474,452**	$ 444,033	$ 303,441	**$ 1,295,731**	$ 1,172,872
Change in non-cash working capital	**14,971**	126,075	(55,632)	**220,895**	$ (26,072)
Transaction costs	**5,079**	2,263	—	**49,045**	—
Additions to exploration and evaluation assets	**1,271**	(40)	(462)	**—**	(6,359)
Additions to oil and gas properties	**(200,537)**	(409,151)	(103,172)	**(1,012,787)**	(515,183)
Payments on lease obligations	**(4,451)**	(4,740)	(851)	**(11,527)**	(3,732)
Cash premiums on derivatives	**—**	—	—	**2,263**	—
Free cash flow	**$ 290,785**	$ 158,440	$ 143,324	**$ 543,620**	$ 621,526

As a result of changes in commodity prices, development plans and capital costs, higher interest rates and debt outstanding, along with the Viking disposition, we no longer expect to generate $1 billion of free cash flow for the period from July 1, 2023 to June 30, 2024, as stated in our press release dated June 20, 2023. We are no longer providing an estimate of our free cash flow for the aforementioned period. Please see our press release dated February 28, 2024 available on SEDAR+ at www.sedarplus.com for our current expectations regarding free cash flow for full year 2024.

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

Total sales, net of blending and other expense per boe

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

Average royalty rate

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

Operating netback per boe

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

Capital Management Measures

Net debt

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

The following table summarizes our calculation of net debt.

	As at		
($ thousands)	**December 31, 2023**	September 30, 2023	December 31, 2022
Credit Facilities	**$ 848,749**	$ 1,028,867	$ 383,031
Unamortized debt issuance costs - Credit Facilities [(1)]	**15,987**	17,889	2,363
Long-term notes	**1,562,361**	1,600,397	547,598
Unamortized debt issuance costs - Long-term notes [(1)]	**35,114**	37,243	6,999
Trade payables	**477,295**	685,392	227,332
Share-based compensation liability	**35,732**	—	54,072
Dividends payable	**18,381**	19,138	—
Other long-term liabilities	**19,147**	—	—
Cash	**(55,815)**	(23,899)	(5,464)
Trade receivables	**(339,405)**	(540,679)	(222,108)
Prepaids and other assets	**(83,259)**	—	(6,377)
Net debt	**$ 2,534,287**	$ 2,824,348	$ 987,446

(1) Unamortized debt issuance costs were obtained from Note 8 Credit Facilities and Note 9 Long-term Notes from the Consolidated Financial Statements for the year ended December 31, 2023. 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 Company's 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, asset retirements obligations settled during the applicable period, transaction costs and cash premiums on derivatives.

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

	Three Months Ended			Years Ended December 31	
($ thousands)	**December 31, 2023**	September 30, 2023	December 31, 2022	**2023**	2022
Cash flows from operating activities	**$ 474,452**	$ 444,033	$ 303,441	**$ 1,295,731**	$ 1,172,872
Change in non-cash working capital	**14,971**	126,075	(55,632)	**220,895**	(26,072)
Asset retirement obligations settled	**7,646**	9,252	7,743	**26,416**	18,351
Transaction costs	**5,079**	2,263	—	**49,045**	—
Cash premiums on derivatives	**—**	—	—	**2,263**	—
Adjusted funds flow	**$ 502,148**	$ 581,623	$ 255,552	**$ 1,594,350**	$ 1,165,151

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As of December 31, 2023, 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 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, 2023. As permitted by applicable securities laws in Canada and the U.S., management excluded from its design and assessment the internal control over financial reporting for Ranger Oil Corporation ("Ranger"), which was acquired on June 20, 2023. The consolidated financial statements as at and for the year ended December 31, 2023 include $3.5 billion of total assets and $691.9 million of revenues, net of royalties from the acquired entity.

The effectiveness of our internal control over financial reporting as of December 31, 2023 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

Management excluded from its design and assessment the internal control over financial reporting for Ranger Oil Corporation ("Ranger") (as permitted by applicable securities laws in Canada and the U.S.), which was acquired on June 20, 2023. Other than Ranger, there has been no change in the Baytex's internal control over financial reporting that occurred during the year ended December 31, 2023 that have materially affected, or are reasonably likely to materially affect, the internal controls over financial reporting.

In accordance with the provision of NI 52-109 and consistent with the SEC guidance, the scope of the evaluation did not include internal controls over financial reporting of Ranger. On June 20, 2023, Baytex completed the acquisition of Ranger, a publicly traded oil and gas company that was listed on the NASDAQ exchange. Ranger's operations have been included in the consolidated financial statements of Baytex since June 20, 2023. However, Baytex has not had sufficient time to appropriately assess the disclosure controls and procedures and internal controls over financial reporting previously used by Ranger and integrate them with those of Baytex. As a result, the certifying officers have limited the scope of their design of disclosure controls and procedures and internal controls over financial reporting to exclude controls, policies and procedures of Ranger (as permitted by applicable securities laws in Canada and the U.S.). Baytex has a program in place to complete its assessment of the controls, policies and procedures of the acquired operations by June 20, 2024.

In 2023, the assets previously held by Ranger contributed revenues of $939.4 million (representing 28% of total revenues) and net income before tax of $165.1 million. At December 31, 2023, current assets of $220.3 million, non-current assets of $3.3 billion, current liabilities of $250.8 million and non-current liabilities of $97.7 million were associated with the acquired entity.

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)	**2023**	2022	2021
Revenues, net of royalties	**$ 2,712,829**	$ 2,326,081	$ 1,529,039
Adjusted funds flow [(1)]	**$ 1,594,350**	$ 1,165,151	$ 745,628
Per common share - basic	**$ 2.26**	$ 2.09	$ 1.32
Per common share - diluted	**$ 2.26**	$ 2.07	$ 1.30
Net (loss) income	**$ (233,356)**	$ 855,605	$ 1,613,600
Per common share - basic	**$ (0.33)**	$ 1.53	$ 2.86
Per common share - diluted	**$ (0.33)**	$ 1.52	$ 2.82
Total assets	**$ 7,460,931**	$ 5,103,769	$ 4,834,643
Credit facilities - principal	**$ 864,736**	$ 385,394	$ 506,514
Long-term notes - principal	**$ 1,597,475**	$ 554,597	$ 885,920
Total sales, net of blending and other expense ($/boe)[(2)]	**$ 70.82**	$ 88.56	$ 60.93
Total production (boe/d)	**122,154**	83,519	80,156

(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: expectation that we can effectively allocate capital across our assets; our intentions of allocating our annual free cash flow to shareholder returns through share buybacks, dividends and debt reduction; that production growth will be driven by our Canadian assets; our commitment to reduce our inactive wellbore count; for 2023, our capital budget, expected average daily production, expected royalty rate and operating expense, transportation expense, general and administrative expense, cash interest expense, current income taxes, lease expenditures and asset retirement obligations settled; the existence, operation and strategy of our risk management program; that we intend to settle outstanding share based compensation awards in cash; the expected time to resolve the reassessment of our tax filings by the Canada Revenue Agency; our objective to maintain a strong balance sheet to execute development programs, deliver shareholder returns and optimize our portfolio through strategic acquisitions; 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. 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. 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: oil and natural gas prices and differentials between light, medium and heavy crude 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; that we will have sufficient financial resources in the future to provide shareholder returns; 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 risk of an extended period of low oil and natural gas prices; risks associated with our ability to develop our properties and add reserves; that we may not achieve the expected benefits of acquisitions and we may sell assets below their carrying value; the availability and cost of capital or borrowing; restrictions or costs imposed by climate change initiatives and the physical risks of climate change; the impact of an energy transition on demand for petroleum productions; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; changes in income tax or other laws or government incentive programs; risks associated with large projects; risks associated with higher a higher concentration of activity and tighter drilling spacing; costs to develop and operate our properties; current or future controls, legislation or regulations; restrictions on or access to water or other fluids; public perception and its influence on the regulatory regime; new regulations on hydraulic fracturing; 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; risks associated with a third-party operating our Eagle Ford properties; additional risks associated with our thermal heavy crude oil projects; our ability to compete with other organizations in the oil and gas industry; risks associated with our use of information technology systems; adverse 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 associated with expansion into new activities; the impact of Indigenous claims; risks of counterparty default; impact of geopolitical risk and conflicts; loss of foreign private issuer status; conflicts of interest between the Company and its directors and officers; variability of share buybacks and dividends; 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, 2023, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission not later than March 31, 2024 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.

Dividend Advisory

Baytex's future shareholder distributions, including but not limited to the payment of dividends, if any, and the level thereof is uncertain. Any decision to pay dividends on the common shares (including the actual amount, the declaration date, the record date and the payment date in connection therewith) will be subject to the discretion of the Board of Directors of Baytex and may depend on a variety of factors, including, without limitation, Baytex's business performance, financial condition, financial requirements, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions and satisfaction of the solvency tests imposed on Baytex under applicable corporate law. Further, the actual amount, the declaration date, the record date and the payment date of any dividend are subject to the discretion of the Board of Directors of Baytex.

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

Crude oil and natural gas prices are volatile. An extended period of low oil and natural gas prices could have a material adverse effect on our business, results of operations, or cash flows and financial condition

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 impacts of geopolitical events, including the Russian Ukrainian war and conflicts in the Middle East, or other adverse economic or political development in the United States, Europe, or Asia, the impact of pandemics/epidemics, government regulation, 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. Additionally, the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. 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 crude oil and heavy crude 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.

There is also a risk that refining capacity in the U.S. Gulf Coast may be insufficient to refine all of the light sweet crude oil being produced in the U.S. If light sweet crude oil production remains at current levels or continues to increase, demand for the light crude oil production from our U.S. operations could result in widening price discounts to the world crude prices.

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.

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 and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays or failure in obtaining governmental, landowner or other stakeholder 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.

The anticipated benefits of acquisitions may not be achieved and the Company may dispose of non-core assets for less than their carrying value on the financial statements

Acquisition of oil and gas properties is a key element of maintaining and growing reserves and production. Competition for these assets has been and will continue to be intense. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive candidates, we may not be able to complete the acquisition or do so on commercially acceptable terms. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired businesses and assets may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Additionally, significant acquisitions can change the nature of our operations and business if acquired properties have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited.

Management continually assesses the value and contribution of our assets. In this regard, non-core assets may be periodically disposed of so that the Company can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Company, if disposed of, may realize less on disposition than their carrying value on the financial statements of the Company.

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.

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, GHG emissions regulation (including carbon taxes) enacted in jurisdictions where we operate will impact us. In addition, certain of our assets have a higher GHG emissions intensity than others and may be disproportionately impacted.

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

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

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

Physical Risk

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rain fall, hurricanes, drought 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 assets are located where they are exposed to forest fires, floods, heavy rains, hurricanes, drought 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.

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 Company cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Company's business and financial condition by decreasing its cash flow from operating activities and the value of its assets.

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 to 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.

Our operations in the United States are concentrated in the Eagle Ford shale of South Texas and as a result are highly exposed to the gulf coast refining complex and events which negatively impact the functioning of infrastructure in that area which could harm our business and, in turn, our financial condition. Such events include adverse weather conditions, terrorism, local market changes, government regulation and taxation which may result in limitations on the U.S.' ability to export crude oil.

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. Contributions of the existing management team to the immediate and near-term operations of the Company are likely to be of central importance. In addition, certain of the Company's current employees may have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. 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.

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. At present, the Canadian tax authorities have reassessed the returns of certain of our subsidiaries. Any such reassessment may have an impact on current and future taxes payable. We believe appropriate provisions for current and deferred income taxes have been made in our Financial Statements; however, it is difficult to predict the outcome of audit findings by tax authorities. These findings may increase the amount of our tax liabilities and adversely affect our business, financial condition and results of operations.

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.

We could experience adverse impacts associated with a high concentration of activity and tighter drilling spacing

We are subject to drilling, completion and operating risks, including our ability to efficiently execute large-scale project development, as we could experience delays, curtailments and other adverse impacts associated with a high concentration of activity and tighter drilling spacing. A higher concentration of activity and tighter drilling spacing may increase the frequency of operational shut-ins and unintentional communication with other adjacent wells and reduce the total recoverable reserves from the reservoir.

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.

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.

Environment

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, state, provincial and local laws and regulations. Environmental legislation provides for, among other things, the initiation and approval of new oil and natural gas projects, and restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural gas industry operations. In addition, such legislation sets 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. New environmental legislation at the federal, state, and provincial levels may increase uncertainty among oil and natural gas industry participants as the new laws are implemented, and the effects of the new rules and standards are felt in the oil and natural gas industry.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liabilities and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge. Although the Company believes that it is in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on our business, financial condition, results of operations and prospects.

The Company may have to pay certain costs associated with abandonment and reclamation

The Company will need to comply with the terms and conditions of environmental and regulatory approvals and all legislation regarding the abandonment of its projects and reclamation of the project lands at the end of their economic life, which may result in substantial abandonment and reclamation costs. Any failure to comply with the terms and conditions of the Company's approvals and legislation may result in the imposition of fines and penalties, which may be material. Generally, abandonment and reclamation costs are substantial. The Company records a provision for abandonment and reclamation costs in its financial statements, this provision requires significant judgement and reflects the Company's best estimate of the costs to complete the required abandonment and reclamation work. Actual results may be significantly different than the estimated amounts.

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.

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

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

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.

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

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

The safe disposal of hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal, 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 Company's costs of compliance.

Our economic 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 derivative 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 derivative 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 derivative 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 economic 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 continue to increase. 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 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, 2023 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.

We are not the operator of a significant portion of our drilling locations in the Eagle Ford 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 a significant portion of our Eagle Ford acreage which is located in the Karnes and Atascosa counties 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.

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: the costs imposed by GHG emissions regulations, 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 in all of its phases. The Company competes with numerous other entities in the exploration for, and the development, production and marketing of, oil and natural gas, as well as 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 Company. As a result, some of the Company's competitors may have greater opportunities and be able to access, services or vendors that the Company is not able to access, thereby limiting its ability to compete.

Our information technology systems are subject to certain risks

We utilize and have become increasingly dependent upon 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 Company'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 Company 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 Company's business, financial condition and results of operations.

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

In the normal course of our operations, we may become involved in, be 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, including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, environmental issues, including claims relating to contamination or 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 effect 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 prior to maturity, 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.

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.

Indigenous Land and Rights Claims

Opposition by Indigenous groups to the conduct of the Company's operations, development or exploratory activities in any of the jurisdictions in which the Company conducts business may negatively impact it in terms of public perception, diversion of management's time and resources, and legal and other advisory expenses, and could adversely impact the Company's progress and ability to explore and develop properties.

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.

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.

Geopolitical risk and conflicts in or around major oil and gas producing nations can significantly impact commodity prices and, therefore the financial condition of the oil and gas industry

Existing or future conflicts in major oil and gas producing nations and the international response may have potential wide-ranging consequences for global market volatility and economic conditions, including affecting crude oil and natural gas prices. Financial and trade sanctions that may be imposed against countries involved in such conflicts may have continued far-reaching effects on the global economy, energy and commodity prices. The short-, medium- and long-term implications of any such conflicts is difficult to predict with any degree of certainty. Depending on the extent, duration, and severity of such conflict(s), it may have the effect of heightening many of the other risks described herein, including, without limitation, risks relating to global market volatility and economic conditions; cybersecurity threats; crude oil and natural gas prices; inflationary pressures, interest rates and costs of capital; and supply chains and cost-effective and timely transportation.

The Company could lose its status as a "foreign private issuer" in the United States

The Company is required to assess its "foreign private issuer" ("FPI") status under U.S. securities laws on an annual basis at the end of its second quarter. While the Company currently qualifies as an FPI, it could lose its FPI status in the future. If the Company were to lose its status as an FPI it would be required to fully comply with both U.S. and Canadian securities and accounting requirements applicable to domestic issuers in each country. In addition, if the Company loses its FPI status, it would be required to report as a U.S. domestic issuer and be subject to other U.S. securities laws applicable to U.S. domestic issuers. The regulatory and compliance costs to our business under U.S. securities laws as a U.S. domestic issuer may be significantly greater than the costs our business incurs as a foreign private issuer. For example, as a U.S. domestic issuer, the Company would be required to file periodic reports and registration statements with the SEC on U.S. domestic issuer forms, which are more detailed and extensive in certain respects than the forms available to the Company as a foreign private issuer. The Company would also be required to report its oil and gas reserves and production information in accordance with applicable U.S. disclosure requirements. Such conversion and modifications would involve additional costs and may restrict the Company’s access to capital markets for a period of time until it has satisfied SEC reporting requirements. In addition, the Company may lose its ability to rely upon exemptions from certain corporate governance requirements on U.S. stock exchanges that are available to FPIs, which could also increase its costs.

Conflicts of interest may arise between the Company and its directors and officers

Circumstances may arise where directors and officers of the Company are directors or officers of other companies involved in the oil and gas industry which are in competition to, or otherwise in conflict with, the interests of the Company. Directors are required to abstain from voting on matters when they are in conflict. Employees, including officers, are not permitted to partake in activities that do not support the best interests of the Company. Where employee conflicts exist, they are to be provided in writing to our Human Resources Department, which discloses all conflicts to Chief Legal Officer. See the Company's Code of Business Conduct and Ethics at www.baytexenergy.com.

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.

Dividends on the Company's Common Shares and Common Share repurchases are variable

The future acquisition by the Company of Common Shares pursuant to a share buyback (including through its NCIB) and the payment of dividends, if any, and the level thereof is uncertain. Any decision to acquire Common Shares pursuant to a share buyback or to pay dividends will be subject to the discretion of the Board and may depend on a variety of factors, including, without limitation, our business performance, financial condition, financial requirements, commodity prices, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions and satisfaction of the solvency tests imposed on the Company under applicable corporate law. In the future, there can be no assurance of the number of Common Shares that the Company will acquire pursuant to a share buyback and there can be no assurance that dividends will be paid or, if paid the amount of such dividends.

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 estimates of proved reserves and proved and 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 and probable reserves disclosed 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(a) OR 15d-14(a) OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Eric T. Greager, 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: February 28, 2024 BAYTEX ENERGY CORP.

/s/ *Eric T. Greager*
Name: Eric T. Greager
Title: President and Chief Executive Officer

Exhibit 99.5

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

I, Chad L. Kalmakoff, 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: February 28, 2024 BAYTEX ENERGY CORP.

/s/ *Chad L. Kalmakoff*
Name: Chad L. Kalmakoff
Title: 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, 2023, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Eric T. Greager, President and Chief Executive Officer, 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: February 28, 2024 BAYTEX ENERGY CORP.

/s/ *Eric T. Greager*
Name: Eric T. Greager
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, 2023, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Chad L. Kalmakoff, Chief Financial Officer of the Company, 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: February 28, 2024 BAYTEX ENERGY CORP.

/s/ *Chad L. Kalmakoff*
Name: Chad L. Kalmakoff
Title: 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 report dated February 28, 2024 on the consolidated financial statements of Baytex Energy Corp. (the "Company") which comprise the consolidated statements of financial position as of December 31, 2023 and 2022, 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, and
- our report dated February 28, 2024 on the effectiveness of the Company's internal control over financial reporting as of December 31, 2023

each of which is included in the Annual Report on Form 40-F of the Company for the fiscal year ended December 31, 2023.

We also consent to the incorporation by reference of such reports in the Registration Statements (No. 333-171568 and No. 333-272971) on Form S-8 and Registration Statement (No. 333-273020) on Form F-3 of the Company.

/s/ KPMG LLP

Chartered Professional Accountants

Calgary, Canada
February 28, 2024

Exhibit 99.9

CONSENT OF INDEPENDENT ENGINEERS

We refer to our report dated February 1, 2024 and effective December 31, 2023, 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 Costs, As of December 31, 2023" (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 and No. 333-272971 on Form S-8 and Registration Statement No. 333-273020 on Form F-3 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, 2023 dated February 28, 2024, 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.

Yours truly,
MCDANIEL & ASSOCIATES CONSULTANTS LTD.

/s/ *Brian R. Hamm*
Brian R. Hamm, P. Eng.
President & CEO

Calgary, Alberta, Canada
February 28, 2024

Baytex Energy Corp.
Supplemental Disclosures about Extractive Activities - Oil and Gas (unaudited)
December 31, 2023

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, 2022 and 2023 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, 2023 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, 2021	89,431	5,400	4,490	111,364	34,814	48,701	—	160,140
Revisions of previous estimates	3,663	1,189	552	11,699	(334)	(320)	—	(15,019)
Improved recovery	—	—	—	—	—	—	—	—
Purchases of minerals in place	—	—	—	—	—	—	—	—
Extensions and discoveries	11,765	1,246	—	14,540	280	286	—	733
Production	(12,848)	(614)	(577)	(15,818)	(3,752)	(2,350)	—	(8,914)
Sales of minerals in place	(1)	(643)	—	(22,996)	—	—	—	—
December 31, 2022	92,009	6,579	4,465	98,790	31,008	46,317	—	136,940
Revisions of previous estimates	(5,696)	529	(400)	(7,097)	(7,169)	(20,990)	—	(59,141)
Improved recovery	—	—	—	—	—	—	—	—
Purchases of minerals in place	6	—	—	—	83,302	20,189	—	116,270
Extensions and discoveries	12,276	2,240	—	9,300	14,226	4,690	—	25,681
Production	(14,940)	(694)	(585)	(15,568)	(9,961)	(3,828)	—	(18,776)
Sales of minerals in place	(10,740)	(12)	—	(247)	—	—	—	—
December 31, 2023	72,915	8,642	3,480	85,178	111,406	46,378	—	200,974
Net proved developed reserves								
End of year 2021	41,918	2,184	592	68,498	18,750	22,334	—	72,257
End of year 2022	46,815	2,436	898	63,494	19,681	20,725	—	60,453
End of year 2023	39,600	3,000	1,564	52,779	54,893	27,460	—	114,346

Baytex Energy Corp.
Supplemental Disclosures about Extractive Activities - Oil and Gas (unaudited)
December 31, 2023

	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 2021	47,513	3,216	3,898	42,866	16,064	26,368	—	87,882
End of year 2022	45,194	4,143	3,567	35,295	11,327	25,592	—	76,487
End of year 2023	33,314	5,641	1,916	32,398	56,513	18,918	—	86,628

	Total				
	Crude Oil (mbbl)	NGL (mbbl)	Bitumen (mbbl)	Natural Gas (mmcf)	Total (mboe)
Net proved reserves					
December 31, 2021	124,245	54,101	4,490	271,504	228,087
Revisions of previous estimates	3,329	869	552	(3,320)	4,196
Improved recovery	—	—	—	—	—
Purchases of minerals in place	—	—	—	—	—
Extensions and discoveries	12,045	1,532	—	15,273	16,122
Production	(16,600)	(2,964)	(577)	(24,732)	(24,262)
Sales of minerals in place	(1)	(643)	—	(22,996)	(4,476)
December 31, 2022	123,017	52,895	4,465	235,729	219,666
Revisions of previous estimates	(12,865)	(20,461)	(400)	(66,238)	(44,766)
Improved recovery	—	—	—	—	—
Purchases of minerals in place	83,308	20,189	—	116,270	122,875
Extensions and discoveries	26,502	6,930	—	34,981	39,262
Production	(24,901)	(4,522)	(585)	(34,344)	(35,732)
Sales of minerals in place	(10,740)	(12)	—	(247)	(10,793)
December 31, 2023	184,321	55,019	3,480	286,151	290,512
Net proved developed reserves					
End of year 2021	60,668	24,518	592	140,755	109,237
End of year 2022	66,496	23,160	898	123,947	111,213
End of year 2023	94,493	30,461	1,564	167,125	154,372
Net proved undeveloped reserves					
End of year 2021	63,578	29,584	3,898	130,749	118,851
End of year 2022	56,521	29,735	3,567	111,782	108,453
End of year 2023	89,827	24,559	1,916	119,026	136,140

Revisions of Previous Estimates

In 2022, the Company realized total net proved revisions of 4,196 mboe. These revisions consisted of: (i) positive revisions of 10,904 mboe, of which 8,840 mboe was in Canada and 2,064 mboe was in the United States ("U.S."), due to an increase in YE 2022 constant pricing as compared to YE 2021 (WTI increased to US$94.14/bbl from US$66.55/bbl), (ii) net negative revisions of 6,709 mboe, of which net negative 5,221 mboe have been realized in our U.S. assets (negative 15,019 mmcf in shale gas) and net negative 1,488 mboe in Canada (negative 6,085 mboe in our Viking asset) due to higher field operating costs resulting from inflationary impacts truncating end of life forecasts and variation in actual performance and forecasted performance.

In 2023, the Company realized total net proved revisions of negative 44,766 mboe. These revisions consisted of: (i) negative revisions of 2,809 mboe in Canada and 1,245 mboe in the US due to a decrease in YE 2023 constant pricing as compared to YE 2022 (WTI decreased to US$78.21/bbl from US$94.14/bbl), (ii) positive revisions of 807 mboe in our Canadian assets as a result of improved performance as compared to previous forecasts, well design changes and changes to operating costs. (iii) negative revisions of 5,877 mboe in our non-operated Eagle Ford assets due to lower performance as compared to previous forecasts and changes in plans for undeveloped locations, and (iv) negative revisions of 30,866 mboe in our non-operated Eagle Ford assets and 4,776 mboe in our Viking assets associated with proved undeveloped locations that were not developed within five years of being booked and so are required to be removed by SEC rules.

Purchases of minerals in place

In 2023 the company acquired 122,875 mboe of reserves primarily in the US in connection with the company’s acquisition of Ranger Oil.

Extensions and Discoveries

In 2022, the Company added net proved reserves of 16,122 mboe. In Canada, 15,434 mboe net proved reserves were added as a result of our 2022 drilling activity. In the U.S., the Company added 688 mboe net proved reserves due to 2022 drilling.

In 2023, the Company added 39,262 mboe of net proved reserves. These additions consisted of 16,066 mboe in Canada and 23,196 mboe in the U.S. due to drilling activity undertaken in 2023.

Sales of Minerals in Place

In 2023, the Company divested 10,793 mboe net proved reserves as a result of a property disposition in our Viking asset in Canada.

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 2023 and 2022.

	Commodity Pricing	
	2023	**2022**
WTI crude (US$/bbl)	$ 78.21	$ 94.14
Edmonton Light crude (Cdn$/bbl)	$ 100.49	$ 119.13
Western Canadian Select crude (WCS) (1) (Cdn$/bbl)	$ 79.89	$ 97.68
AECO spot (Cdn$/mmbtu)	$ 2.84	$ 5.62
Henry Hub (US$/mmbtu)	$ 2.59	$ 6.25
Exchange rate (US$/Cdn$)	0.7410	0.7710

(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)	**2023**	**2022**	**2023**	**2022**	**2023**	**2022**
Future cash inflows	$ 6,306,909	$ 10,216,200	$ 13,067,619	$ 8,202,831	$ 19,374,528	$ 18,419,030
Future production costs	(2,488,443)	(3,259,376)	(3,690,844)	(2,074,525)	(6,179,287)	(5,333,901)
Future development costs (1)	(1,535,153)	(1,978,527)	(3,976,050)	(953,024)	(5,511,203)	(2,931,551)
Future income taxes	(171,413)	(810,870)	(206,428)	(901,361)	(377,841)	(1,712,231)
Future net cash flows (2)	2,111,900	4,167,427	5,194,297	4,273,921	7,306,197	8,441,348
Deduct: 10% annual discount factor	(583,252)	(1,269,964)	(2,069,662)	(1,949,809)	(2,652,914)	(3,219,773)
Standardized measure (2)	$ 1,528,648	$ 2,897,463	$ 3,124,635	$ 2,324,112	$ 4,653,283	$ 5,221,575

(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, 2023 (thousands of Canadian dollars)		Canada	United States	Total [1]
Balance, beginning of year	$	2,897,463	$ 2,324,112	$ 5,221,575
Sales, net of production costs		(922,466)	(994,723)	(1,917,189)
Net change in prices and production costs related to future production		(1,294,788)	(854,833)	(2,149,621)
Changes in previously estimated future development costs incurred during the period		(273,910)	(73,764)	(347,674)
Development costs incurred during the period		463,198	549,589	1,012,787
Extensions, discoveries and improved recovery, net of related costs		488,266	381,810	870,076
Revisions of previous quantity estimates		(229,669)	(1,199,229)	(1,428,898)
Sales of reserves in place		(369,943)	—	(369,943)
Purchases of reserves in place		70	2,398,015	2,398,085
Accretion of discount		343,679	273,609	617,288
Net change in income taxes		426,748	320,049	746,797
Balance, end of year [1]	$	1,528,648	$ 3,124,635	$ 4,653,283

As at December 31, 2022 (thousands of Canadian dollars)		Canada	United States	Total [1]
Balance, beginning of year	$	1,553,924	$ 1,648,430	$ 3,202,354
Sales, net of production costs		(1,131,785)	(582,176)	(1,713,961)
Net change in prices and production costs related to future production		1,933,064	1,337,782	3,270,846
Changes in previously estimated future development costs incurred during the period		(444,451)	(277,658)	(722,109)
Development costs incurred during the period		374,443	140,740	515,183
Extensions, discoveries and improved recovery, net of related costs		462,066	26,732	488,798
Revisions of previous quantity estimates		493,498	73,356	566,854
Sales of reserves in place		(22,955)	—	(22,955)
Purchases of reserves in place		—	—	—
Accretion of discount		161,174	183,719	344,893
Net change in income taxes		(481,515)	(226,813)	(708,328)
Balance, end of year [1]	$	2,897,463	$ 2,324,112	$ 5,221,575

(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, 2023 (thousands of Canadian dollars)		Canada	United States	Total
Proved properties	$	6,522,443	$ 9,003,574	$ 15,526,017
Unproved properties		90,919	—	90,919
Total capital costs		6,613,362	9,003,574	15,616,936
Accumulated depletion and impairment		(4,526,811)	(4,380,173)	(8,906,984)
Net capitalized costs	$	2,086,551	$ 4,623,401	$ 6,709,952

As at December 31, 2022 (thousands of Canadian dollars)		Canada	United States	Total
Proved properties	$	6,698,047	$ 5,344,169	$ 12,042,216
Unproved properties		85,981	82,703	168,684
Total capital costs		6,784,028	5,426,872	12,210,900
Accumulated depletion and impairment		(4,179,986)	(3,241,464)	(7,421,450)
Net capitalized costs	$	2,604,042	$ 2,185,408	$ 4,789,450

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

As at December 31, 2023 (thousands of Canadian dollars)		Canada	United States	Total
Property acquisition costs				
Proved properties	$	1,556	$ 18,891	$ 20,447
Unproved properties		18,467	—	18,467
Development costs [1]		463,198	549,589	1,012,787
Exploration costs [2]		—	—	—
Total	$	483,221	$ 568,480	$ 1,051,701

As at December 31, 2022 (thousands of Canadian dollars)		Canada	United States	Total
Property acquisition costs				
Proved properties	$	551	$ —	$ 551
Unproved properties		801	—	801
Development costs [1]		374,443	140,740	515,183
Exploration costs [2]		6,359	—	6,359
Total	$	382,154	$ 140,740	$ 522,894

(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, 2023 (thousands of Canadian dollars except per boe amounts)		Canada	United States	Total
Petroleum and natural gas revenues, net of royalties	$	1,515,873	$ 1,196,956	$ 2,712,829
Less:				
Operating costs, production and mineral taxes		368,605	202,234	570,839
Transportation and blending expense		289,127	24,981	314,108
Exploration and evaluation		8,896	—	8,896
Depletion and impairment loss		668,232	1,205,210	1,873,442
Operating income (loss)		181,013	(235,469)	(54,456)
Income tax expense (recovery)		44,602	(50,838)	(6,236)
Results of operations [1]	$	136,411	$ (184,631)	$ (48,220)

For year ended December 31, 2022 (thousands of Canadian dollars except per boe amounts)		Canada	United States	Total
Petroleum and natural gas revenues, net of royalties	$	1,649,133	$ 676,948	$ 2,326,081
Less:				
Operating costs, production and mineral taxes		327,894	94,772	422,666
Transportation and blending expense		238,015	—	238,015
Exploration and evaluation		30,239	—	30,239
Depletion and impairment reversal		141,542	171,747	313,289
Operating income		911,443	410,429	1,321,872
Income tax expense		226,038	88,612	314,650
Results of operations [1]	$	685,405	$ 321,817	$ 1,007,222

(1) Excludes corporate overhead and interest costs.