BAYTEX

2023 ANNUAL REPORT

CREATING **ENERGY**
CREATING **VALUE**

NYSE | TSX BTE

2023

HIGHLIGHTS

Ranger Oil acquisition
adds quality scale
in the Eagle Ford

Increased shareholder returns to
50%
of free cash flow

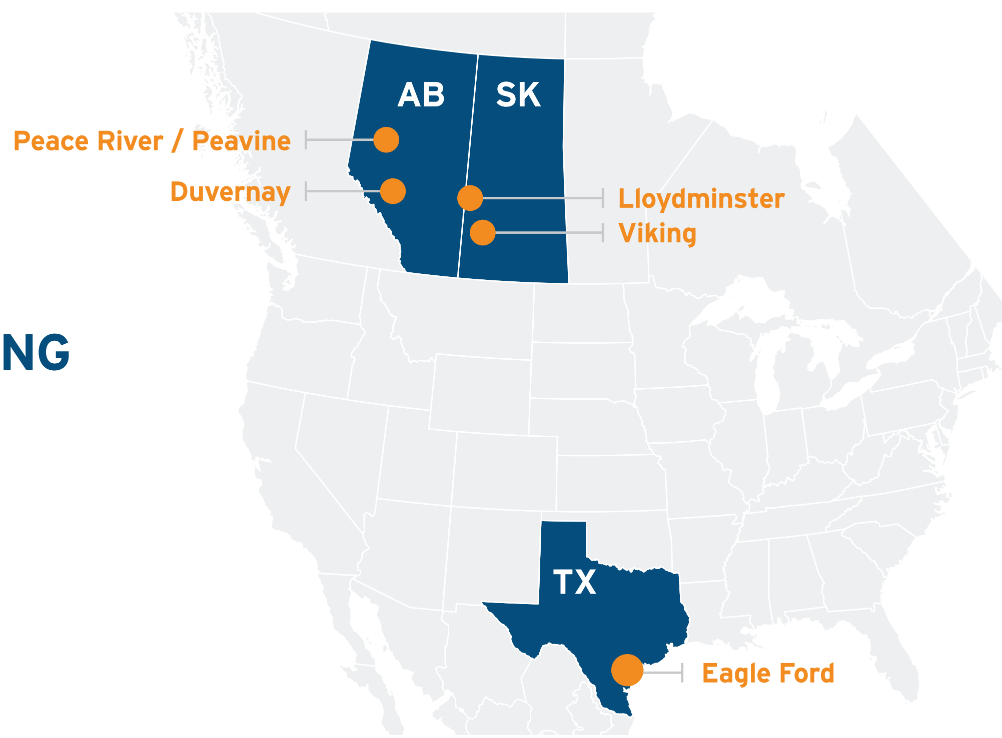
122,154 boe/d
for the full-year 2023

Introduced
quarterly dividend of
$0.0225 cents per share

$544 million
of free cash flow

65% reduction
in GHG emissions intensity,
relative to our 2018 baseline

OUR OPERATING AREAS



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NYSE | TSX BTE

2023
SUMMARY

FINANCIAL	Twelve Months Ended December 31, 2023		Twelve Months Ended December 31, 2022	
(thousands of Canadian dollars, except per common share amounts)				
Petroleum and natural gas sales	**$**	**3,382,621**	$	2,889,045
Adjusted funds flow (1)		**1,594,350**		1,165,151
Per share - basic		**2.26**		2.09
Per share - diluted		**2.26**		2.07
Free cash flow (2)		**543,620**		621,526
Per share - basic		**0.77**		1.11
Per share - diluted		**0.77**		1.10
Cash flows from operating activities		**1,295,731**		1,172,872
Per share - basic		**1.84**		2.10
Per share - diluted		**1.84**		2.08
Net income (loss)		**(233,356)**		855,605
Per share - basic		**(0.33)**		1.53
Per share - diluted		**(0.33)**		1.52
Dividends declared		**37,519**		-
Per share - basic		**0.045**		-
Capital Expenditures				
Exploration and development expenditures	**$**	**1,012,787**	$	521,542
Acquisitions and (divestitures)		**(121,342)**		(24,297)
Total oil and natural gas capital expenditures	**$**	**891,445**	$	497,245
Net Debt				
Credit facilities	**$**	**864,736**	$	385,394
Long-term notes		**1,597,475**		554,597
Long-term debt (3)		**2,462,211**		939,991
Working capital deficiency (2)		**72,076**		47,455
Net debt (1)	**$**	**2,534,287**	$	987,446
Shares Outstanding - basic (thousands)				
Weighted average		**704,896**		557,986
End of period		**821,681**		544,930
BENCHMARK PRICES				
Crude oil				
WTI (US$/bbl)	**$**	**77.62**	$	94.23
MEH oil (US$/bbl)		**79.29**		97.79
MEH oil differential to WTI (US$/bbl)		**1.67**		3.57
Edmonton par ($/bbl)		**100.46**		119.95
Edmonton par differential to WTI (US$/bbl)		**(3.18)**		(2.07)
WCS heavy oil ($/bbl)		**79.58**		98.94
WCS differential to WTI (US$/bbl)		**(18.65)**		(18.21)
Natural gas				
NYMEX (US$/mmbtu)	**$**	**2.74**	$	6.64
AECO ($/mcf)		**2.93**		5.56
CAD/USD average exchange rate		**1.3495**		1.3016

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.
(3) Calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at *www.sedarplus.com*.

2023

SUMMARY

OPERATING	Twelve Months Ended December 31, 2023		Twelve Months Ended December 31, 2022	
Daily Production				
Light oil and condensate (bbl/d)		**53,389**		33,101
Heavy oil (bbl/d)		**35,460**		28,993
NGL (bbl/d)		**14,304**		7,575
Total liquids (bbl/d)		**103,153**		69,669
Natural gas (mcf/d)		**114,010**		83,101
Oil equivalent (boe/d @ 6:1) (1)		**122,154**		83,519
Netback (thousands of Canadian dollars)				
Total sales, net of blending and other expense (2)	**$**	**3,157,819**	$	2,699,591
Royalties		**(669,792)**		(562,964)
Operating expense		**(570,839)**		(422,666)
Transportation expense		**(89,306)**		(48,561)
Operating netback (2)	**$**	**1,827,882**	$	1,665,400
General and administrative		**(69,789)**		(50,270)
Cash financing and interest		**(159,823)**		(80,386)
Realized financial derivatives loss		**36,212**		(334,481)
Other (3)		**(40,132)**		(35,112)
Adjusted funds flow (4)	**$**	**1,594,350**	$	1,165,151
Netback per boe (2)				
Total sales, net of blending and other expense (2)	**$**	**70.82**	$	88.56
Royalties (5)		**(15.02)**		(18.47)
Operating expense (5)		**(12.80)**		(13.86)
Transportation expense (5)		**(2.00)**		(1.59)
Operating netback (2)	**$**	**41.00**	$	54.64
General and administrative (5)		**(1.57)**		(1.65)
Cash financing and interest (5)		**(3.58)**		(2.64)
Realized financial derivatives loss (5)		**0.81**		(10.97)
Other (3)		**(0.90)**		(1.16)
Adjusted funds flow (4)	**$**	**35.76**	$	38.22

Notes:

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

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

(3) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and share-based compensation. Refer to the 2023 MD&A for further information on these amounts.

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

(5) Calculated as royalties, operating, transportation expense, general and administrative expense, cash interest expense or realized financial derivatives gain (loss) divided by barrels of oil equivalent production volume for the applicable period.

BAYTEX ANNOUNCES FOURTH QUARTER AND FULL YEAR 2023 FINANCIAL AND OPERATING RESULTS AND YEAR END RESERVES

CALGARY, ALBERTA (February 28, 2024) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three months and year ended December 31, 2023 (all amounts are in Canadian dollars unless otherwise noted).

"Our 2023 results demonstrate the strength of our oil-weighted portfolio. The strategic acquisition of Ranger added quality scale in the Eagle Ford and reinforced the resiliency and sustainability of our business. In 2023, we increased production per share by 16% and fourth quarter production exceeded guidance with continued strong results in the Eagle Ford and Peavine. During 2023, we increased shareholder returns to 50% of free cash flow, increased our share buyback program and introduced a quarterly dividend. We are well-capitalized and remain committed to creating long-term value and increasing shareholder returns," commented Eric T. Greager, President and Chief Executive Officer.

2023 Highlights

- Completed the acquisition of Ranger Oil Corporation ("Ranger") on June 20, 2023.
- Reported cash flows from operating activities of $474 million ($0.57 per basic share) in Q4/2023 and $1,296 million ($1.84 per basic share) for 2023.
- Delivered adjusted funds flow(1) of $502 million ($0.60 per basic share) in Q4/2023 and $1,594 million ($2.26 per basic share) for 2023.
- Generated free cash flow(2) of $291 million ($0.35 per basic share) in Q4/2023 and $544 million ($0.77 per basic share) for 2023.
- Increased direct shareholder returns to 50% of free cash flow(2) and returned $260 million to shareholders. Repurchased 40.5 million common shares for $222 million, representing 4.7% of our shares outstanding, and declared two quarterly dividends of $0.0225 per share, totaling $38 million in 2023.
- Increased production per basic share by 16% in 2023, compared to 2022. Production for the full-year 2023 averaged 122,154 boe/d (85% oil and NGL), compared to 83,519 boe/d in 2022 (84% oil and NGL).
- Production in Q4/2023 averaged 160,373 boe/d (83% oil and NGL), exceeding guidance of 158,000 to 160,000 boe/d, and up 6% from Q3/2023 on exploration and development expenditures of $199 million, 10% below guidance.
- Divested of our Viking assets at Forgan and Plato in southwest Saskatchewan (production of approximately 4,000 boe/d) for proceeds of $160 million, including closing adjustments.
- Improved our cash cost structure (operating, transportation, and general & administrative expenses) in Q4/2023 by 12% on a boe basis, as compared to Q4/2022.
- Maintained balance sheet strength with a total debt to EBITDA(3) ratio(2) of 1.1x. During the fourth quarter we reduced our net debt(1) by 10% ($290 million).
- Reduced our GHG emissions intensity in 2023 by 9% from 2022 levels and achieved our 65% reduction target, relative to our 2018 baseline, two years early.
- Proved developed producing reserves increased by 49%, from 124 MMboe to 185 MMboe(4). Proved reserves increased by 55%, from 264 MMboe to 410 MMboe(4). Proved plus probable reserves increased by 51%, from 438 MMboe to 663 MMboe(4).
- At year-end 2023, the present value of our 2P reserves, discounted at 10% before tax, is estimated to be $7.8 billion ($5.9 billion at year-end 2022).

We recorded a non-cash impairment of $834 million on our legacy non-operated Eagle Ford and retained Viking assets as the carrying value of our oil and gas properties exceeded their recoverable amounts. This resulted in a net loss of $626 million ($0.75 per basic share) in Q4/2023 and $233 million ($0.33 per basic share) in 2023.

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.
(3) Calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.com.
(4) Baytex's year-end 2023 reserves were evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel"), an independent qualified reserves evaluator, in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101").

Strategy and 2024 Outlook

We are a well-capitalized, North American oil-weighted producer with 60% of our producing assets located in the Eagle Ford with the balance in western Canada. We are committed to a disciplined, returns-based capital allocation philosophy to drive increased per-share returns. The key elements of our business strategy include:

- Disciplined Capital Allocation. Each of our core assets has 10 or more years of development inventory at our planned pace of development. This provides us the ability to efficiently allocate capital and respond to changes in regional commodity prices and other economic factors. Over our five-year outlook (2024 to 2028), we expect to generate annual production growth of 1% to 4%, with production reaching approximately 170,000 boe/d in 2028.

- Free Cash Flow(1). Our commitment to disciplined capital allocation across our portfolio is expected to generate meaningful free cash flow(1). We intend to allocate 50% of free cash flow(1) to debt repayment and 50% to shareholder returns, which includes a combination of share buybacks and a quarterly dividend.

- Financial Strength. We are committed to maintaining a strong balance sheet and significant financial liquidity. We are in a strong financial position with a total debt to EBITDA(2) ratio(1) of 1.1x. Upon reaching a total debt(2) target of $1.5 billion, we intend to direct 75% of free cash flow(1) to shareholder returns.

In January, extremely cold temperatures across North America, followed by heavy rainfall in Texas, led to production disruptions. Our production has been restored, however, first quarter production will be approximately 2,000 boe/d lower than our budget expectation. Despite this, our 2024 guidance remains unchanged with exploration and development expenditures of $1.2 to $1.3 billion and production of 150,000 to 156,000 boe/d. In 2024, we intend to progress the Pembina Duvernay, further delineate our Clearwater and Mannville heavy oil positions, and deliver strong drilling and completion performance in the Eagle Ford and Viking.

Based on the forward strip(3), we expect to generate approximately $575 million of free cash flow(1) in 2024. Our capital program is weighted to the first and third quarters and as a result, we expect to generate a significant amount of our 2024 free cash flow(1) during the second and fourth quarters.

2023 Results

On June 20, 2023, we closed the acquisition of Ranger, adding quality scale in the Eagle Ford and reinforcing a resilient and sustainable business. In conjunction with closing, we increased direct shareholder returns to 50% of free cash flow(1), which allowed us to increase the value of our share buyback program and introduce a dividend. The remainder of our free cash flow(1) was allocated to debt reduction.

In 2023, we returned $260 million to shareholders through our share buyback program and dividend. Our normal course issuer bid allows for the purchase of up to 68.4 million common shares during the 12-month period ending June 28, 2024. Through December 31, 2023, we repurchased 40.5 million common shares for $222 million, representing 4.7% of our shares outstanding, at an average price of $5.48 per share. In addition, we declared two quarterly dividends of $0.0225 per share, totaling $38 million.

We increased production per basic share by 16% in 2023, compared to 2022. Production in Q4/2023 averaged 160,373 boe/d (83% oil and NGL), exceeding our guidance for the quarter of 158,000 to 160,000 boe/d, and up 6% from 150,600 boe/d (85% oil and NGL) in Q3/2023. Production for the full-year 2023 averaged 122,154 boe/d, compared to 83,519 boe/d in 2022.

Exploration and development expenditures totaled $1,013 million in 2023 as compared to our annual guidance of $1,035 million. We participated in the drilling of 303 (254.0 net) wells in 2023. For the second half of 2023, exploration and development expenditures totaled $608 million, consistent with our plan following the Ranger acquisition.

Our business improved structurally through the Ranger acquisition with increased exposure to premium U.S. Gulf Coast pricing and improved margins. In Q4/2023, over 40% of our liquids production received WTI equivalent pricing and our realized light oil and condensate price in the Eagle Ford was $105.83/bbl, or US$77.60/bbl. In addition, we improved our cash cost structure (operating, transportation, general & administrative expenses) in Q4/2023 by 12% on a boe basis compared to Q4/2022.

(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 press release for further information.
(2) Calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.com.
(3) 2024 pricing assumptions: WTI - US$75/bbl; WCS differential - US$16/bbl; NYMEX Gas - US$2.25/MMbtu; and Exchange Rate (CAD/USD) - 1.35.

On December 11, 2023, we completed the divestiture of Viking assets at Forgan and Plato in southwest Saskatchewan for proceeds of $160 million, including closing adjustments. Proceeds from the sale were applied against our credit facilities. Production from the assets at the time of the sale was approximately 4,000 boe/d (100% light and medium crude oil). We incurred a non-cash loss of $144 million related to the sale.

During the fourth quarter we reduced our net debt(1) by 10% ($290 million) due to a combination of free cash flow generation, net proceeds from the Viking divestiture and the impact of a strengthening Canadian dollar, relative to the U.S. dollar, on our U.S. dollar denominated debt. Our total debt(2) at December 31, 2023 was $2.5 billion and we have $588 million of undrawn capacity on our credit facilities.

We employ a disciplined commodity hedging program to help mitigate the volatility in revenue due to changes in commodity prices. In 2023, our hedging program generated realized financial derivatives gains of $36 million. For 2024, we have entered into hedges on approximately 40% of our net crude oil exposure utilizing two-way collars with an average floor price of US$60/bbl and an average ceiling price of US$96/bbl. A complete listing of our financial derivative contracts can be found in Note 18 to our 2023 financial statements.

At year-end 2023, we identified indicators of impairment on our legacy non-operated Eagle Ford and retained Viking assets. As a result, we recorded total non-cash impairments of $834 million in Q4/2023 as the carrying value of our oil and gas properties exceeded their recoverable amounts. This non-cash impairment resulted in a net loss of $626 million ($0.75 per basic share) in Q4/2023 and $233 million ($0.33 per basic share) in 2023.

Operations

The integration of the Ranger assets has progressed well. We continue to optimize base performance and remain focused on strong drilling and completion performance. For 2024, we are targeting an 8% improvement in our operated drilling and completion costs per completed lateral foot over 2023.

In the Eagle Ford, we continue to deliver strong results across the black oil, volatile oil, and condensate thermal maturity windows. In Q4/2023, 9 (8.9 net) operated wells were brought onstream, bringing the total operated wells on production since closing the Ranger acquisition to 22 (21.8 net) wells. The nine wells brought onstream during the fourth quarter generated an average 30-day initial production rate of approximately 1,600 boe/d (80% oil and NGL) per well. On our non-operated acreage, there were no new wells brought onstream during the fourth quarter.

In the Pembina Duvernay, we commenced drilling operations in January and to-date have drilled three of seven wells planned for 2024. Completion activities are scheduled to commence in May. We continue to advance our understanding of the reservoir and believe the asset offers significant economic inventory growth potential.

In our heavy oil business unit, our Clearwater production averaged 16,338 boe/d during the fourth quarter, up 48% from Q4/2022. At Peavine, we brought 31 (31.0 net) wells onstream during 2023 and initial well performance continues to outperform type curve assumptions. In 2024, we will see continued exploration across our heavy oil portfolio with up to 14 stratigraphic test wells planned.

Quarterly Dividend

The Board of Directors has 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.

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

Environmental Stewardship

The energy industry and society are undergoing an evolution toward lower carbon intensity, and we believe that oil and gas will be instrumental in this energy evolution. As a responsible energy producer, we are committed to reducing greenhouse gas (“GHG”) emissions from our operations, minimizing freshwater use, and reclaiming our assets at the end of their economic life.

GHG Emissions

We are committed to monitoring GHG emissions from our operations, setting targets to reduce our GHG emissions intensity, and pursuing cost-effective strategies to produce energy for society with a lower carbon intensity. Our emissions reduction strategy includes increased gas conservation and destruction, reusing associated gas as fuel for field activities, capturing and reducing emissions from storage tanks, along with monitoring and preventing fugitive emissions.

Our corporate objective set in 2019 was to reduce our GHG emissions intensity (kg of CO2e per boe) by 65% by 2025 (set on our Canadian assets), relative to our 2018 baseline. In 2023, we invested $12 million in GHG reduction capital, reduced our GHG emissions intensity by 9% and achieved our 65% target two years early.

Continuous improvement is an important element of our corporate culture and we intend to set the bar higher. We are in the process of road mapping 2030 GHG reduction targets. Further details will be available in our 2023 ESG Report to be released in July 2024.

In 2024, we will invest approximately $18 million as part of our GHG mitigation program as we continue to invest in monitoring and lowering GHG emissions from our operations.

GHG Emissions Intensity (Scope 1 and Scope 2)(1) - Segment Canada

	2018 Baseline	2019	2020	2021	2022	2023(2)	2025 Target
kg CO_2e/boe	122	103	64	57	47	43	43

Water Management

As a responsible energy producer we are committed to pursuing water management strategies that minimize our freshwater use to help support long-term water security and maintain healthy ecosystems in our operating areas. In 2024, we anticipate investing $3 million in water management to expand our water storage and recycling infrastructure.

Abandonment and Reclamation

Our commitment to responsible resource development also extends to the retirement of our assets at the end of their economic life. We plan for full lifecycle development of our properties, which includes the abandonment, reclamation, and full restoration at the end of asset life. At December 31, 2020, we had an end of life well inventory of approximately 4,500 wells. We have committed to reducing this well inventory to zero by 2040, which represents proactive management of future financial obligations as well as regulatory compliance.

In 2023, we invested $26 million to complete 291 well abandonments. In 2024, we will continue our abandonment and reclamation program with approximately $30 million being directed to pipeline, wellbore and facility decommissioning along with well site reclamations.

Abandonment and Reclamation

	2018	2019	2020	2021	2022	2023	2024 Plan
Number of wells abandoned (gross)	110	113	99	237	379	291	260
Spending in abandonment/reclamation ($ million) (3)	$ 14	$ 15	$ 9	$ 10	$ 34	$ 26	$ 30

(1) Corporate emissions are reported based on the operating control method of the GHG Protocol. GHG emissions from 2018-2022 are calculated using the Global Warming Potential ("GWP") values from the IPCC’s Fifth Assessment ("AR5"). We have restated historical emissions with the update to AR5, the operating control method of the GHG Protocol.
(2) 2023 data is not yet third party verified.
(3) Spending includes government grants received for abandonment and reclamations of $2 million in 2020, $3 million in 2021 and $16 million in 2022.

Year-end 2023 Reserves

Baytex's year-end 2023 proved and probable reserves were evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel"), an independent qualified reserves evaluator. All of our oil and gas properties were evaluated in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") using the average commodity price forecasts and inflation rates of McDaniel, GLJ Petroleum Consultants ("GLJ") and Sproule Associates Limited ("Sproule") as of January 1, 2024.

For additional information regarding Baytex's reserves as at December 31, 2023, see Baytex's Annual Information Form for the year ended December 31, 2023 on Baytex's SEDAR+ profile at www.sedarplus.com, and Baytex's U.S. Form 40-F for the year ended December 31, 2023 on EDGAR at www.sec.gov/edgar.shtml., each of which are anticipated to be filed on February 28, 2024.

Reserves Summary

On June 20, 2023, Baytex completed the strategic acquisition of Ranger, adding quality scale in the Eagle Ford and reinforcing a resilient and sustainable business. Our 2023 reserves report reflects this acquisition with a meaningful increase in our reserves base.

- Proved developed producing ("PDP") reserves increased by 49%, from 124 MMboe to 185 MMboe. Proved reserves ("1P") increased by 55%, from 264 MMboe to 410 MMboe. Proved plus probable reserves ("2P") increased by 51%, from 438 MMboe to 663 MMboe.
- Reserves on a 1P basis are comprised of 82% oil and NGLs (46% light oil, 23% NGLs, 12% heavy oil and 1% bitumen) and 18% natural gas.
- In Canada, we invested $463 million on exploration and development expenditures and replaced 131% of production on a 2P basis, net of the divestiture of our Viking assets at Forgan and Plato. The divestiture reduced 1P and 2P reserves by 11 MMboe and 17 MMboe, respectively.
- In the Eagle Ford, 1P and 2P reserves increased 117% and 130%, respectively. Reserves associated with the Ranger assets total 175 MMboe on a 1P basis, and 258 MMboe on a 2P basis, consistent with our assessment of Ranger's reserves at year-end 2022. The Ranger acquisition enhanced the quality of Baytex's reserves base, adding high value light oil and natural gas.
- Future development costs ("FDC") on a 1P basis increased to $6.0 billion ($2.7 billion at year-end 2022) and on a 2P basis, increased to $9.1 billion ($4.3 billion at year-end 2022). The increase in FDC is largely attributable to the Ranger acquisition, as well as modest inflationary pressures across our portfolio.
- Finding and development ("F&D") costs, including changes in FDC, were $24.23/boe for PDP reserves, $29.82/boe for 1P reserves and $28.68/boe for 2P reserves.
- Generated a PDP recycle ratio of 1.7x and a 1P recycle ratio of 1.4x based on a 2023 operating netback(1) of $41.00/boe.
- At year-end 2023, the present value of our 2P reserves, discounted at 10% before tax, is estimated to be $7.8 billion ($5.9 billion at year-end 2022). The increase is largely attributable to the Ranger acquisition and partially offset by the divestiture of our Viking assets at Forgan and Plato and technical revisions associated with our legacy non-operated Eagle Ford asset and retained Viking assets.

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

The following table sets forth our gross and net reserves volumes at December 31, 2023 by product type and reserves category. Please note that the data in the table may not add due to rounding.

Reserves Summary

Reserves Summary	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids [3] (Mbbls)	Conventional Natural Gas [4] (MMcf)	Shale Gas (MMcf)	Total [5] (Mboe)
Gross [1]									
Proved producing	9,690	70,573	31,218	1,679	113,159	38,394	52,758	145,556	184,606
Proved developed non-producing	414	3,703	1,416	—	5,533	1,814	1,205	6,761	8,675
Proved undeveloped	15,699	88,506	18,445	2,105	124,754	54,631	23,948	201,607	216,978
Total proved	25,803	162,782	51,078	3,783	243,447	94,840	77,910	353,924	410,259
Total probable	14,997	85,238	32,935	45,754	178,923	42,334	38,246	151,764	252,925
Proved plus probable	40,799	248,020	84,013	49,537	422,370	137,173	116,156	505,688	663,184
Net [2]									
Proved producing	9,128	53,944	26,283	1,564	90,918	29,180	47,825	111,300	146,619
Proved developed non-producing	383	2,789	1,260	—	4,431	1,361	1,076	5,087	6,819
Proved undeveloped	14,882	68,154	16,292	1,916	101,243	41,630	20,760	154,239	172,039
Total proved	24,392	124,886	43,834	3,480	196,591	72,172	69,661	270,627	325,478
Total probable	13,910	65,548	27,331	36,517	143,306	32,687	33,578	118,279	201,303
Proved plus probable	38,302	190,434	71,165	39,997	339,897	104,859	103,238	388,906	526,781

Notes:

(1) "Gross" reserves means the total working interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.

(2) "Net" reserves means Baytex's gross reserves less all royalties payable to others plus royalty interest reserves.

(3) Natural Gas Liquids includes condensate.

(4) Conventional Natural Gas includes associated, non-associated and solution gas.

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

Reserves Reconciliation

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

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

	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (3) (Mbbls)	Conventional Natural Gas (4) (MMcf)	Shale Gas (MMcf)	Total (5) (Mboe)
December 31, 2022	41,951	48,563	51,058	4,608	146,180	69,765	86,872	202,967	264,251
Extensions	2,039	21,367	9,402	—	32,808	8,587	1,845	40,849	48,510
Technical Revisions (2)	(1,952)	(1,472)	2,176	(261)	(1,509)	(3,997)	4,451	(7,782)	(6,062)
Acquisitions	—	108,091	7	—	108,098	26,379	—	143,499	158,394
Dispositions	(11,417)	—	—	—	(11,417)	(14)	(267)	—	(11,475)
Economic Factors	180	25	741	75	1,021	36	928	86	1,226
Production	(4,999)	(13,793)	(12,305)	(638)	(31,735)	(5,916)	(15,919)	(25,695)	(44,586)
December 31, 2023	25,803	162,782	51,078	3,783	243,447	94,840	77,910	353,924	410,259

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

	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (3) (Mbbls)	Conventional Natural Gas (4) (MMcf)	Shale Gas (MMcf)	Total (5) (Mboe)
December 31, 2022	21,881	20,719	34,526	45,751	122,877	28,728	45,786	84,633	173,342
Extensions	289	10,650	3,326	—	14,265	4,510	899	18,478	22,004
Technical Revisions (2)	(1,467)	(1,080)	(5,336)	25	(7,857)	(1,730)	(8,835)	(5,274)	(11,939)
Acquisitions	—	54,926	2	—	54,928	10,794	—	53,785	74,685
Dispositions	(5,772)	—	—	—	(5,772)	(4)	(71)	—	(5,787)
Economic Factors	65	23	416	(22)	482	36	467	142	620
Production	—	—	—	—	—	—	—	—	—
December 31, 2023	14,997	85,238	32,935	45,754	178,923	42,334	38,246	151,764	252,925

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

	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (3) (Mbbls)	Conventional Natural Gas (4) (MMcf)	Shale Gas (MMcf)	Total (5) (Mboe)
December 31, 2022	63,832	69,283	85,584	50,359	269,058	98,493	132,658	287,600	437,593
Extensions	2,328	32,017	12,728	—	47,073	13,096	2,744	59,327	70,514
Technical Revisions (2)	(3,419)	(2,552)	(3,160)	(236)	(9,367)	(5,727)	(4,384)	(13,056)	(18,001)
Acquisitions	—	163,017	9	—	163,026	37,172	—	197,284	233,079
Dispositions	(17,188)	—	—	—	(17,188)	(18)	(338)	—	(17,262)
Economic Factors	245	49	1,157	52	1,503	73	1,395	228	1,846
Production	(4,999)	(13,793)	(12,305)	(638)	(31,735)	(5,916)	(15,919)	(25,695)	(44,586)
December 31, 2023	40,799	248,020	84,013	49,537	422,370	137,173	116,156	505,688	663,184

Notes:

(1) "Gross" reserves means the total working interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.

(2) Negative 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.

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

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

Future Development Costs

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

Future Development Costs ($ millions)	Proved Reserves	Proved Plus Probable Reserves
2024	1,038	1,070
2025	1,256	1,313
2026	1,334	1,442
2027	1,227	1,580
2028	1,060	1,451
Remainder	72	2,196
Total FDC undiscounted	5,986	9,051

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

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

$ millions except for per boe amounts		2023		2022		2021		3 Year
Proved plus Probable Reserves								
Finding & Development Costs								
Exploration and development expenditures	$	1,012.8	$	521.5	$	313.3	$	1,847.6
Net change in Future Development Costs	$	841.2	$	588.6	$	147.4	$	1,577.2
Gross Reserves additions (MMboe)		64.6(1)		26.2		18.8		109.6
F&D Costs ($/boe)	$	28.68	$	42.34	$	24.55	$	31.24
Finding, Development & Acquisition ("FD&A") Costs								
Exploration and development expenditures and net acquisitions	$	3,948.5	$	497.2	$	307.1	$	4,752.8
Net change in Future Development Costs	$	4,763.6	$	537.6	$	144.4	$	5,445.6
Gross Reserves additions (MMboe)		270.2		17.2		18.4		305.8
FD&A Costs ($/boe)	$	32.25	$	60.05	$	24.55	$	33.35
Proved Reserves								
Finding & Development Costs								
Exploration and development expenditures	$	1,012.8	$	521.5	$	313.3	$	1,847.6
Net change in Future Development Costs	$	491.7	$	320.1	$	308.6	$	1,120.4
Gross Reserves additions (MMboe)		50.5(1)		21.4		35.2		107.0
F&D Costs ($/boe)	$	29.82	$	39.40	$	17.67	$	27.74
Finding, Development & Acquisition Costs								
Exploration and development expenditures and net acquisitions	$	3,948.5	$	497.2	$	307.1	$	4,752.8
Net change in Future Development Costs	$	3,290.6	$	285.0	$	316.8	$	3,892.4
Gross Reserves additions (MMboe)		190.6		16.6		36.1		243.2
FD&A Costs ($/boe)	$	37.98	$	47.25	$	17.30	$	35.55
Proved Developed Producing Reserves								
Finding & Development Costs								
Exploration and development expenditures	$	1,012.8	$	521.5	$	313.3	$	1,847.6
Gross Reserves additions (MMboe)		41.8(1)		27.2		38.2		107.2
F&D Costs ($/boe)	$	24.23	$	19.20	$	8.20	$	17.24
Finding, Development & Acquisition Costs								
Exploration and development expenditures and net acquisitions	$	3,948.5	$	497.2	$	307.1	$	4,752.8
Gross Reserves additions (MMboe)		104.8		26.0		38.1		168.9
FD&A Costs ($/boe)	$	37.69	$	19.13	$	8.06	$	28.14

Note:

(1) Gross reserve additions with respect to finding & development costs include 4.7 MMboe of PDP reserve additions, 6.8 MMboe of proved reserves additions and 10.2 MMboe of proved plus probable reserves additions, which in each case, reflect reserves developed on the acquired Ranger assets after closing of the acquisition. In the reserves reconciliation, these reserve additions are included in the Acquisitions category to align with NI 51-101.

Forecast Prices and Costs

The following table summarizes the forecast prices used in preparing the estimated reserves volumes and the net present values of future net revenues at December 31, 2023. The estimated future net revenue to be derived from the production of the reserves is based on the following average of the price forecasts of McDaniel, GLJ and Sproule as of January 1, 2024.

Year	WTI Crude Oil US$/bbl	Edmonton Light Crude Oil $/bbl	Western Canadian Select $/bbl	Henry Hub US$/MMbtu	AECO Spot $/MMbtu	Inflation Rate %/Yr	Exchange Rate $US/$Cdn
2023 act.	77.55	100.40	79.60	2.55	2.95	3.9	0.740
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
Thereafter		Escalation rate of 2.0%				2.0	0.755

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

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

Reserves at December 31, 2023 ($ millions, discounted at)	0%	5%	10%	15%
Proved developed producing	4,443	3,991	3,507	3,133
Proved developed non-producing	291	223	186	161
Proved undeveloped	3,295	2,037	1,264	761
Total proved	8,029	6,252	4,957	4,055
Probable	7,773	4,445	2,843	1,971
Total Proved Plus Probable (before tax)	15,802	10,697	7,800	6,026

Note:

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

Additional Information

Our audited consolidated financial statements for the year ended December 31, 2023 and the related Management's Discussion and Analysis of the operating and financial results can be accessed on our website at www.baytexenergy.com and will be available shortly through SEDAR+ at www.sedarplus.com and EDGAR at www.sec.gov/edgar.shtml.

Advisory Regarding Forward-Looking Statements

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

Specifically, this report contains forward-looking statements relating to but not limited to: our 2024 strategy including our commitment to a disciplined, returns-based capital allocation philosophy and the anticipated effect of such philosophy on per-share returns; that we expect to allocate capital efficiently and respond to changes in regional commodity prices and economic factors; expected annual production growth over the next five years and our projected 2028 production; our intention to allocate free cash flow to each of debt repayment and shareholder returns (including share buybacks and quarterly dividends) and the expected amount of such free cash flow to be allocated; our expectation to generate meaningful free cash flow in 2024, including the anticipated amount and timing thereof; our intention to direct additional free cash flow to shareholder returns once reaching our total debt target; our total debt target; our intended exploration plans across our heavy oil portfolio, including our drilling plans; our commodity hedging program, the percentage of our 2024 net crude exposure that is hedged, and the ability of such program to mitigate volatility in commodity prices; our targeted improvement in operated drilling and completion costs per lateral foot; our guidance regarding exploration and development expenditures and production in 2024; our drilling plans in the Pembina Duvernay and our intention to progress the Pembina Duvernay, delineate our Clearwater and Mannville heavy oil positions and deliver strong drilling and completion performance in the Eagle Ford and Viking regions; our commitment to monitoring GHG emissions, setting targets and pursuing cost-effective decarbonization strategies; our 2025 GHG emissions intensity reduction target and our strategies to reach the target; our 2024 expected investment into GHG mitigation, to expand our water storage and recycling infrastructure, and into wellbore and facility decommissioning along with well site reclamations; our abandonment and reclamation commitments, including the anticipated number of wells; future development costs, F&D and FD&A; forecast prices for oil and natural gas; forecast inflation and exchange rates; and the net present value before income taxes of the future net revenue attributable to our reserves. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that they can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: oil and natural gas prices and differentials between light, medium and heavy crude oil prices; well production rates and reserve volumes; success obtained in drilling new wells; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; operating costs; 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; our ability to market oil and natural gas successfully; 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; risks associated with achieving our total debt target, production guidance, exploration and development expenditures guidance; the amount of free cash flow we expect to generate; risk that the board of directors determines to allocate capital other than as set forth herein; 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; risk that we do not achieve our GHG emissions intensity reduction target; 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.

The future acquisition of our 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.*

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 on February 28, 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.

This report 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 expected 2024 free cash flow; and our intentions of allocating our annual free cash flow to shareholder returns through a share buyback and debt reduction; 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 report 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 report was made as of the date of this report 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 report is not conclusive and is subject to change.

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

Specified Financial Measures

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

Non-GAAP Financial Measures

Total sales, net of blending and other expense

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

Operating netback

Operating netback is 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.

The following table reconciles operating netback 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

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, transaction costs, additions to exploration and evaluation assets, additions to oil and gas properties, payments on lease obligations, 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 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)
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

Working capital deficiency

Working capital deficiency is calculated as cash, trade receivables, and prepaids and other assets net of trade payables, dividends payable, other long-term liabilities and share-based compensation liability. Working capital deficiency is used by management to measure the Company's liquidity. At December 31, 2023, the Company had $587.8 million of available credit facility capacity to cover any working capital deficiencies.

The following table summarizes the calculation of working capital deficiency.

	As at		
($ thousands)	**December 31, 2023**	September 30, 2023	December 31, 2022
Cash	**$ (55,815)**	$ (23,899)	$ (5,464)
Trade receivables	**(339,405)**	(540,679)	(222,108)
Prepaids and other assets	**(83,259)**	—	(6,377)
Trade payables	**477,295**	685,392	227,332
Share-based compensation liability	**35,732**	—	54,072
Other long-term liabilities	**19,147**	—	—
Dividends payable	**18,381**	19,138	—
Working capital deficiency	**$ 72,076**	$ 139,952	$ 47,455

Non-GAAP Financial Ratios

Total sales, net of blending and other expense per boe

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

Capital Management Measures

Net debt

We 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.

Adjusted funds flow

Adjusted funds flow is used to monitor operating performance and our ability to generate funds for exploration and development expenditures and settlement of abandonment obligations. Adjusted funds flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital, asset retirement obligations settled, transaction costs, and cash premiums on derivatives during the applicable period.

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

Advisory Regarding Oil and Gas Information

The reserves information contained in this report has been prepared in accordance with NI 51-101. Complete NI 51-101 reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2023, which will be filed on February 28, 2024. Listed below are cautionary statements that are specifically required by NI 51-101:

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

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

In the Eagle Ford, Baytex's net drilling locations include 358 proved and 148 probable locations as at December 31, 2023 and 318 unbooked locations. In the Viking, Baytex's net drilling locations include 586 proved and 173 probable locations as at December 31, 2023 and 238 unbooked locations. In Peace River (including Clearwater), Baytex's net drilling locations include 64 proved and 52 probable locations as at December 31, 2023 and 331 unbooked locations. In Lloydminster, Baytex's net drilling locations include 73 proved and 69 probable locations as at December 31, 2023 and 263 unbooked locations. In the Duvernay, Baytex's net drilling locations include 23 proved and 24 probable locations as at December 31, 2023 and 174 unbooked locations.

Throughout this report, "oil and NGL" refers to heavy oil, bitumen, light and medium oil, tight oil, condensate and natural gas liquids ("NGL") product types as defined by NI 51-101. The following table shows Baytex's disaggregated production volumes for the three and twelve months ended December 31, 2023. The NI 51-101 product types are included as follows: "Heavy Oil" - heavy oil and bitumen, "Light and Medium Oil" - light and medium oil, tight oil and condensate, "NGL" - natural gas liquids and "Natural Gas" - shale gas and conventional natural gas.

	Three Months Ended December 31, 2023					Twelve Months Ended December 31, 2023				
	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada – Heavy										
Peace River	10,494	8	29	10,576	12,294	10,209	9	44	11,258	12,138
Lloydminster	12,736	40	—	1,445	13,017	11,852	23	—	1,298	12,092
Peavine	16,338	—	—	—	16,338	13,399	—	—	—	13,399
Canada - Light										
Viking	—	10,560	158	11,592	12,650	—	13,126	196	11,834	15,295
Duvernay	—	2,805	2,129	6,748	6,058	—	1,884	1,195	3,840	3,719
Remaining Properties	—	730	622	18,211	4,386	—	656	654	19,224	4,514
United States										
Eagle Ford	—	55,981	20,223	116,548	95,629	—	37,691	12,214	66,556	60,997
Total	39,569	70,123	23,160	165,121	160,373	35,460	53,389	14,303	114,011	122,154

This report contains metrics commonly used in the oil and natural gas industry, such as "finding and development costs", "finding, development and acquisition costs", "PDP recycle ratio" and "1P recycle ratio." These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included in this report to provide readers with additional measures to evaluate Baytex's performance, however, such measures are not reliable indicators of Baytex's future performance and future performance may not compare to Baytex's performance in previous periods and therefore such metrics should not be unduly relied upon.

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

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

Recycle ratio is calculated by dividing operating netback on a per boe basis by finding and development costs for the particular reserves category.

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

Notice to United States Readers

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

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

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

BAYTEX ENERGY CORP.
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

($ thousands, except per common share amounts)	2023 Q4	2023 Q3	2023 Q2	2023 Q1	2022 Q4	2022 Q3	2022 Q2	2022 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.

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 was 7.6% 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 receive one 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

ABBREVIATIONS

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

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

CORPORATE INFORMATION

BOARD OF DIRECTORS

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Chairman of the Board

Eric T. Greager
Director

Tiffany (TJ) Thom Cepak [1,3]
Director

Trudy M. Curran [2,4]
Director

Don G. Hrap [1,3]
Director

Angela S. Lekatsas [1,4]
Director

Jennifer A. Maki [1,2]
Director

David L. Pearce [2,3]
Director

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

Jeffrey E. Wojahn [2,4]
Director

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

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Chief Financial Officer

Chad E. Lundberg
Chief Operating Officer

James R. Maclean
Chief Legal Officer and Corporate Secretary

Brian G. Ector
Senior Vice President, Capital Markets and Investor Relations

Kendall D. Arthur
Senior Vice President and General Manager, Canadian Heavy Oil Operations

Julia C. Gwaltney
Senior Vice President and General Manager, U.S. Eagle Ford Operations

Nicole M. Frechette
Vice President and General Manager, Canadian Light Oil Operations

Chris M.P. Lessoway
Vice President, Finance and Treasurer

AUDITORS
KPMG LLP

RESERVES ENGINEERS
McDaniel & Associates Consultants Ltd.

TRANSFER AGENT
Odyssey Trust Company

EXCHANGE LISTINGS
New York Stock Exchange
Toronto Stock Exchange
Symbol: **BTE**

Design: ARTHUR / HUNTER
Printing: Merrill Corporation

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