BAYTEX

INVESTOR PRESENTATION

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

JANUARY 2025

ADVISORY

In this presentation, we refer to certain specified financial measures which do not have any standardized meaning prescribed by International Financial Reporting Standards (“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 presentation also contains oil and gas disclosures, various industry terms, and forward-looking statements, including various assumptions on which such forward-looking statements are based and related risk factors. Please see the Company’s disclosures located at the end of this presentation for further details regarding these matters.

All slides in this presentation should be read in conjunction with “Forward Looking Statements Advisory”, “Specified Financial Measures Advisory”, “Capital Management Measures Advisory” and “Advisory Regarding Oil and Gas Information”.

This presentation should be read in conjunction with the Company’s consolidated interim unaudited financial statements and Management’s Discussion and Analysis (“MD&A”) for the period ended September 30, 2024.

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. The future oriented financial information and forward-looking statements are made as of January 2, 2025 and Baytex disclaims any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

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

A DIVERSIFIED NORTH AMERICAN E&P OPERATOR

OUR OPERATING AREAS

Market Summary

Ticker Symbol	TSX, NYSE | BTE
Average Daily Volume (1)	Canada: 11.4 million | US: 11.9 million
Shares Outstanding (2)	774 million
Market Capitalization / Enterprise Value (3)	$2.9 billion / $5.4 billion
Annual Dividend per Share | Dividend Yield (4)(5)	$0.09 | 2.4%

Operating Statistics

Production (working interest) (6)	148 - 152 Mboe/d
Production Mix (6)	85% liquids
E&D Expenditures (6)	$1.2 - $1.3 billion
Reserves – 2P Gross (7)	663 MMboe
Net Acres	1.6 million

2025 Production by Business Unit

- U.S. Light Oil (Eagle Ford)
- Canada Light Oil (Duvernay /Viking)
- Canada Heavy Oil (Peace River/Peavine/Lloydminster)
- Other

2025 Production by Commodity

- Heavy Oil
- Light Oil
- NGLs
- Natural Gas

(1) Average daily trading volumes for December 2024. Volumes are a composite of all exchanges.
(2) Shares outstanding as at December 31, 2024.
(3) Enterprise value based on closing share price on the Toronto Stock Exchange on December 31, 2024 and net debt as at September 30, 2024. Enterprise value is calculated as market capitalization plus net debt and is used to assess the valuation of the Company. Net debt is a capital management measure. Refer to the Capital Management Measures section in this presentation for further information.
(4) Refer to the Dividend Advisory section in the presentation for further information.
(5) Dividend yield is calculated by dividing the annualized per share dividend by the market share price for the applicable period.
(6) Production, production mix, and exploration and development ("E&D") expenditures represents 2025 guidance.
(7) 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"). See "Advisories".

Operational Excellence to Deliver Long-Term Value and Increasing Shareholder Returns

Disciplined Reinvestment and Capital Allocation	Prioritizing free cash flow(1) High-quality oil-weighted portfolio with more than 10-years of drilling inventory Track record of new discoveries
Shareholder Returns	Allocating 50% of free cash flow to the balance sheet and 50% to shareholder returns (share buybacks and quarterly dividend) Returned ~ $550 million to shareholders over last 6 quarters, including repurchasing 10% of shares outstanding
Maintain Financial Strength	Net debt reduced ~ 12% over last 5 quarters Significant credit capacity with strong long-term notes maturity schedule Resilient through the commodity price cycles

(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 Advisory section in this presentation for further information.

Delivering substantial free cash flow[1] and shareholder returns

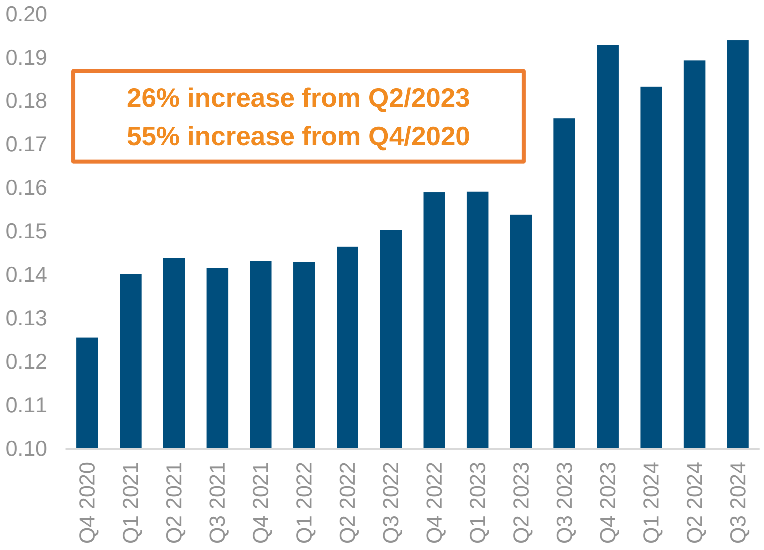
Strong Execution	Production and E&D expenditures consistent with full-year plan Generated $401 million of free cash flow[1] and returned $220 million to shareholders
Eagle Ford Activity	42 operated Lower Eagle Ford wells onstream Identified Upper Eagle Ford development areas with 4 wells onstream Successful refrac (Medina 3H)
Pembina Duvernay Results	Advanced Pembina Duvernay with successful 7-well program Significant improvement in drilling efficiency, facility / completion optimization and well performance Acquired 31 sections of prospective lands adjacent to existing acreage
Heavy Oil Development	Strong well performance at Peavine Land extensions at Peace River and Lloydminster Continued exploration success

(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 Advisory section in this presentation for further information.

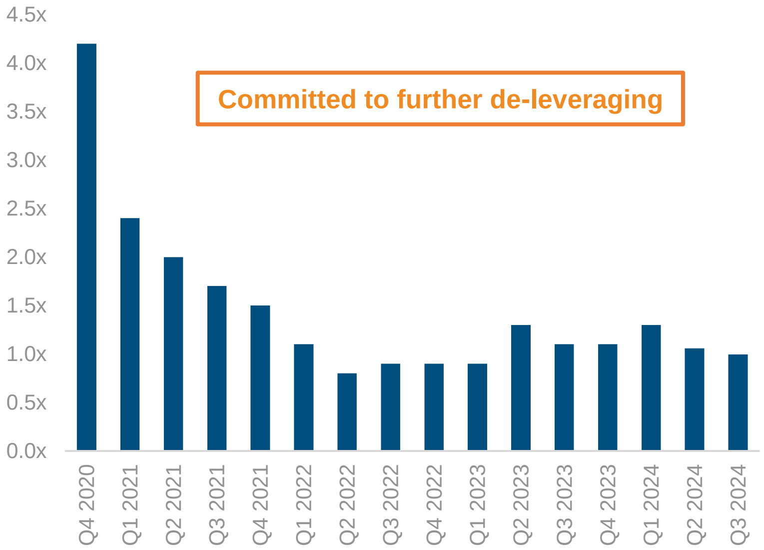
CREATING SHAREHOLDER VALUE

Delivering production per share growth while improving financial leverage

Production (boe/d) per thousand shares



Total debt[(1)] to Bank EBITDA[(1)(2)]



(1) Calculated in accordance with the amended credit facilities agreement which is available on the SEDAR+ website at www.sedarplus.ca.
(2) Leverage ratio calculation based on quarter-end total debt and quarterly Bank EBITDA annualized.

2025 OUTLOOK

Disciplined Reinvestment and Capital Allocation

Prioritizing free cash flow[1]

Moderating growth profile and delivering **stable production**

Strong drilling, completion and operating performance across portfolio

- Operationally efficient, level loaded pace of development in the Eagle Ford
- Further advance Pembina Duvernay
- Capital efficient heavy oil development

150,000 boe/d
2025 mid-point production

2025 Guidance	
E&D Expenditures	$1.2 - $1.3 billion
Production	148,000 - 152,000 boe/d
Oil and NGLs	85%

Operating Area	Net Wells Onstream	E&D Expenditures ($MM)
U.S. Light Oil [2]	54	$730
Canada Light Oil [3]	99	$270
Canada Heavy Oil [4]	112	$250
Total	265	$1,250

(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 Advisory section in this presentation for further information.
(2) U.S. Light Oil includes operated / non-operated Eagle Ford. Exploration and development budget is US$520 million. Based on a Canada-U.S. exchange rate of 1.40 CAD/USD.
(3) Canada Light Oil includes Duvernay / Viking.
(4) Canada Heavy Oil includes Peace River (Bluesky) / Peavine (Clearwater) / Lloydminster (Mannville).

2025 RETURN OF CAPITAL

Return 50% of free cash flow[(1)] to shareholders

Free Cash Flow Priorities

Return of Capital[(1)] and Strengthening Balance Sheet

Share Buybacks

Consistent program to meet shareholder return commitment

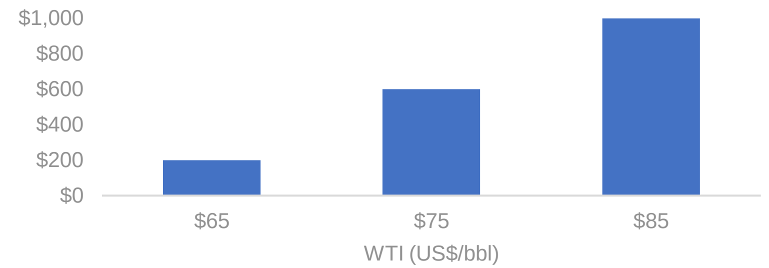
Base Dividend

Quarterly dividend of $0.0225 per share ($0.09 per share annualized)

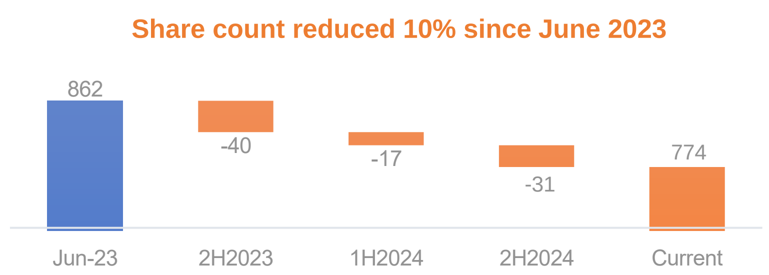
Balance Sheet

Reduce financial leverage and maintain prudent debt maturity schedule

2025 Free Cash Flow[(1)] ($ millions)[(2)]



Shares Repurchased (millions)



(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 Advisory section in this presentation for further information.

(2) 2025 free cash flow sensitivity based on mid-point of 2025 annual guidance, WTI prices of US$65/bbl, US$75/bbl and US$85/bbl, and the following commodity price assumptions: WCS differential – US$13/bbl; NYMEX Gas - US$3.25/MMbtu; Exchange Rate (CAD/USD) – 1.40.

Commitment to a Strong Balance Sheet

Significant credit capacity

Resilient through the commodity price cycles

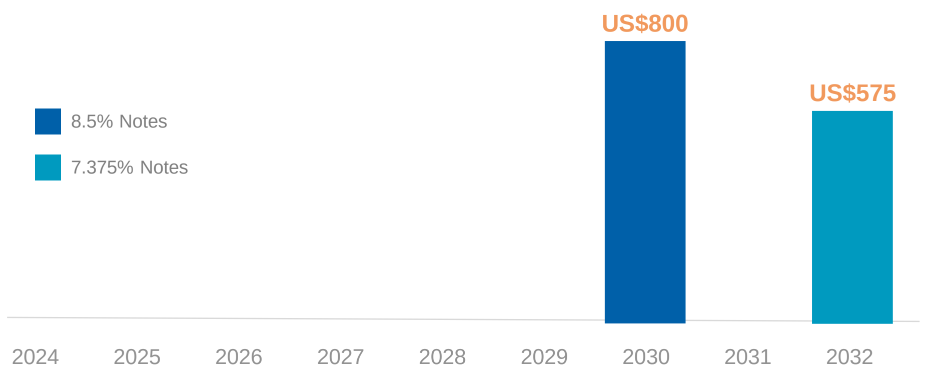
Strong long-term notes maturity schedule

68% unutilized credit capacity

Total debt[2] target of $1.5 billion (~ 0.7x total debt to EBITDA[2] at US$70 WTI)

Total Debt [1][2]	C$ millions
Credit facilities [3]	$466
Long-term notes	
8.500% notes due April 1, 2030	$1,080
7.375% notes due April 1, 2032	$777
Total long-term notes	$1,857
Total debt	$2,323

Long-Term Notes Maturity Schedule (US$ millions)



(1) Total debt as at September 30, 2024.
(2) Calculated in accordance with the amended credit facilities agreement which is available on the SEDAR+ website at www.sedarplus.ca.
(3) Revolving credit facilities total US$1.1 billion and mature May 2028. The revolving credit facilities are not borrowing base facilities and do not require annual or semi-annual reviews.

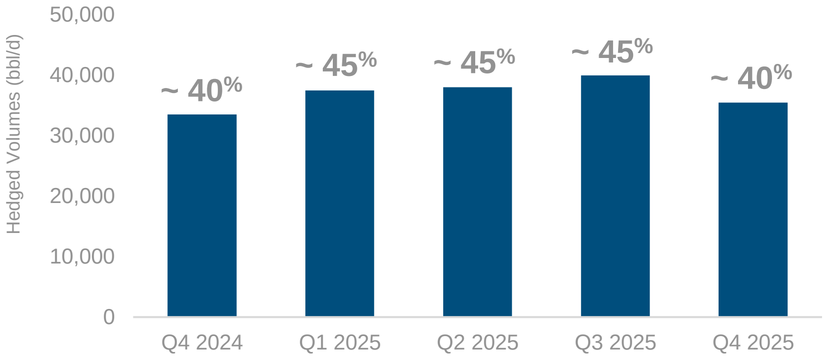
CRUDE OIL HEDGE PORTFOLIO

Balanced Approach to Risk Management

Target up to 45% of Net Crude Oil Volumes(1)

Disciplined hedge program to help mitigate volatility in revenue due to changes in commodity prices

Utilize wide **2-way collars** to ensure modest returns at lower commodity prices while maintaining exposure to upside and minimizing costs



Collars (Weighted Average)					
Ceiling (US$)	$91.82	$89.41	$87.48	$80.00	$80.00
Floor (US$)	$60.00	$60.00	$60.00	$60.00	$60.00

(1) Percentage of hedged volumes are based on 2024 production guidance (excluding NGLs), net of royalties.

FIVE-YEAR OUTLOOK (2024 – 2028)

Sustainable plan[(1)(2)] delivers significant value

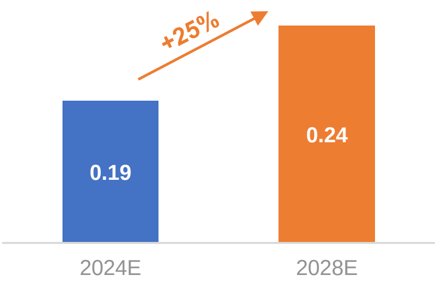
Prioritizing free cash flow[(3)]
50% to balance sheet; 50% to shareholder returns[(4)]

0-4% annual production growth
Base plan delivers stable production; optionality for organic growth under higher commodity pries

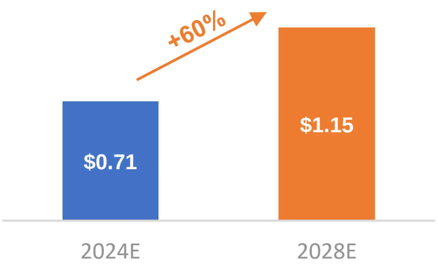
Strong economics across portfolio
> 10 years of drilling inventory

Balance sheet strength
Target total debt to Bank EBITDA[(4)] ratio < 1.0x

Production
(boe/d per thousand shares)



Free Cash Flow[(3)] (per share)[(4)]



(1) Five-year outlook released on December 3, 2024 and based on a mid-cycle WTI price of US$75/bbl WTI. Year one (2024) based on nine-month actual results and 2024 guidance. Year two (2025) based on mid-point of 2025 guidance. Years three through five (2026 to 2028) assume 0% annual production growth at flat US$75/bbl WTI. Budget and forecast beyond 2025 have not been finalized and are subject to a variety of factors including prior year's results. For illustrative purposes only and should not be relied upon as indicative of future results. Baytex's actual results may vary.

(2) Commodity price assumptions 2024: WTI - US$75/bbl; WCS differential – US$15/bbl; NYMEX gas – US$2.30/MMbtu; exchange rate (CAD/USD) – 1.36. Commodity price assumptions 2025 to 2028: WTI - US$75/bbl; WCS differential – US$13/bbl; NYMEX gas – US$3.25/MMbtu; exchange rate (CAD/USD) – 1.40.

(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 Advisory section in this presentation for further information.

(4) Calculated in accordance with the amended credit facilities agreement which is available on the SEDAR+ website at www.sedarplus.ca.

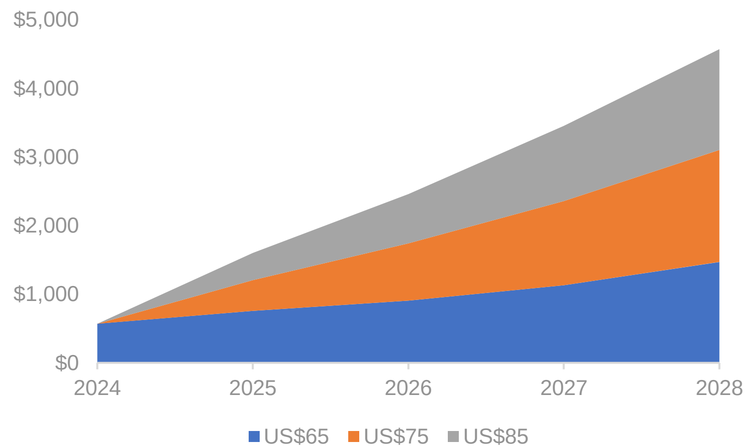
FIVE-YEAR OUTLOOK (2024 – 2028)

Shareholder Returns(1)(2)

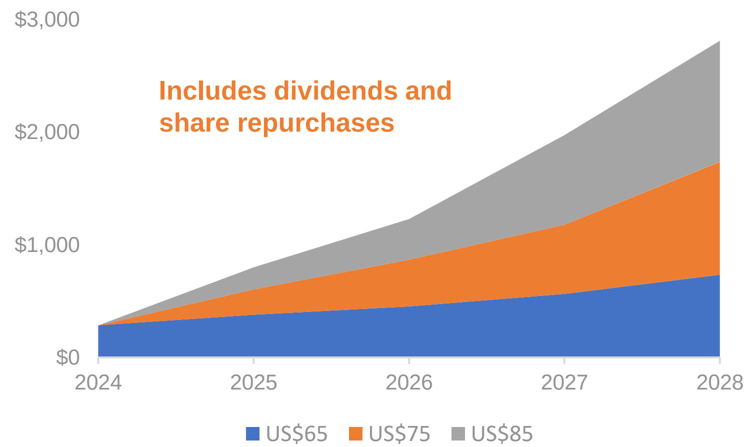
Compelling Returns Profile

Underpinned by disciplined reinvestment and capital allocation

Free Cash Flow(3) over Five-Year Outlook ($ millions)



Return of Capital(3) to Shareholders over Five-Year Outlook ($ millions)



(1) Five-year outlook released on December 3, 2024 and based on a mid-cycle WTI price of US$75/bbl WTI. Year one (2024) based on nine-month actual results and 2024 guidance. Year two (2025) based on mid-point of 2025 guidance. Years three through five (2026 to 2028) assume 0% annual production growth at flat US$65/bbl and US$75/bbl WTI scenarios, and ~ 2% annual production growth at flat US$85/bbl scenario. Budget and forecast beyond 2025 have not been finalized and are subject to a variety of factors including prior year's results. For illustrative purposes only and should not be relied upon as indicative of future results. Baytex's actual results may vary.

(2) Commodity price assumptions 2024: WTI - US$75/bbl; WCS differential – US$15/bbl; NYMEX gas – US$2.30/MMbtu; exchange rate (CAD/USD) – 1.36. Commodity price assumptions 2025 to 2028 at WTI prices of US$65/bbl, US$75/bbl and US$85/bbl: WCS differential – US$13/bbl; NYMEX gas – US$3.25/MMbtu; exchange rate (CAD/USD) – 1.40.

(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 Advisory section in this presentation for further information.

ASSET OVERVIEW

BUSINESS UNIT HIGHLIGHTS



	Light Oil – USA (Eagle Ford)	Light Oil – Canada (Viking/Duvernay)	Heavy Oil – Canada (Peace River/Peavine/ Lloydminster)
Production (2025E)	85,000 boe/d	19,000 boe/d	42,000 boe/d
% Liquids	81%	84%	96%
Land (net acres)	182,000	311,000	710,000
2P Reserves (Gross) (1)	418 MMboe	95 MMboe	139 MMboe
Asset Level Free Cash Flow (% of corporate) (2)	60%	5%	35%
Drilling Locations (net risked) (3)	~ 850	~ 1,200	~ 850
Individual Well Economics (4) (5)			
IRRs	45% to 90%	55% to 90%	95% to > 250%
Payouts	14 to 26 months	14 to 21 months	8 to 13 months
CROCI (6)	2.1x to 2.5x	2.0x to 2.7x	2.4x to 4.0x

(1) 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"). See "Advisories".

(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 Advisory section in this presentation for further information.

(3) Net locations includes proved plus probable undeveloped reserves locations at year-end 2023 and unbooked future locations. See "Advisories".

(4) Individual well economics based on constant pricing and costs and Baytex's internal assumptions using an average type curve for wells within each asset that are expected to be developed in the five-year outlook (representing ~ 40% of our inventory of booked and un-booked risked locations).

(5) Commodity price assumptions: WTI – US$75/bbl; WCS differential – US$13/bbl; NYMEX Gas - US$3.25/MMbtu; Exchange Rate (CAD/USD) – 1.40.

(6) Cash Return on Capital Invested ("CROCI") is a supplementary financial measure calculated as the undiscounted cash flow stream for an individual well divided by the cost to drill, complete, equip and tie-in a well.

U.S. LIGHT OIL: EAGLE FORD

Strong Operating Capability

Increased Scale in a Premier Basin with Strong Market Access

Eagle Ford

269,000 gross acres, 70% operated

Lowers full-company cash cost structure, improves operating netbacks and margins

Provides exposure to premium light oil U.S. Gulf Coast pricing

Expect to bring 54 net wells to sales (~ 75% operated) in 2025

2025 Operated Activity

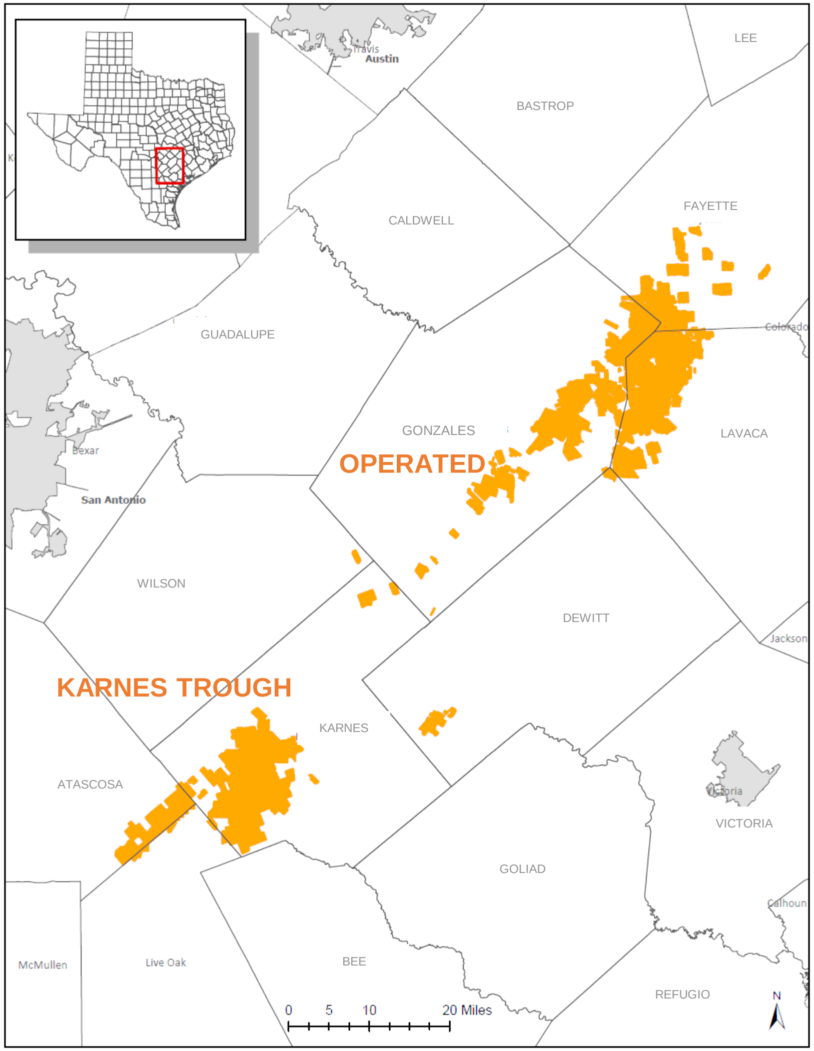
Expect to bring 41 operated wells onstream - **37 Lower Eagle Ford wells and 4 Upper Eagle Ford wells**

Typical 30-day peak crude oil rates in the black and volatile oil windows ~ 700 to 800 bbl/d (900 to 1,100 boe/d) per well

~ US$10 million well cost based on 9,500 foot completed lateral length

Level loaded pace of development, running a 2 rig and 1 frac crew program for most of the year

Targeting an **8% improvement in drilling and completion costs per lateral foot,** over 2024



U.S. LIGHT OIL: OPERATED EAGLE FORD

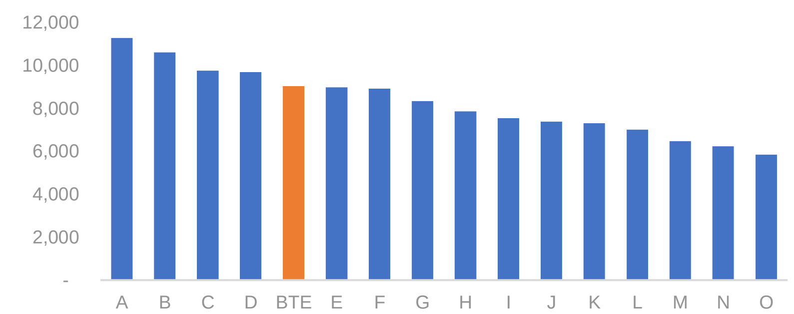
Strong results across thermal maturity windows
black & volatile oil and condensate

Top quartile performance
first 3 months crude oil production

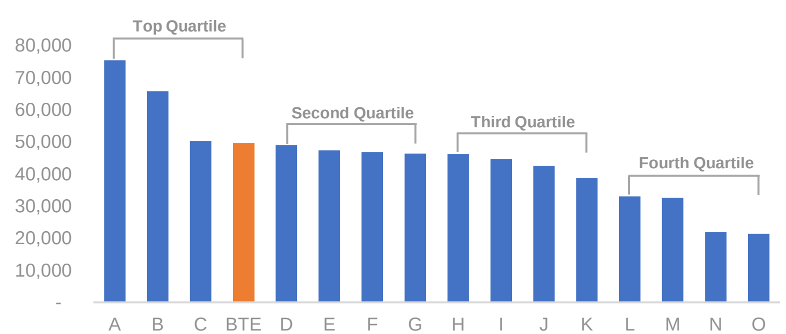
Second quartile performance
crude oil productivity per lateral foot

Above average lateral lengths

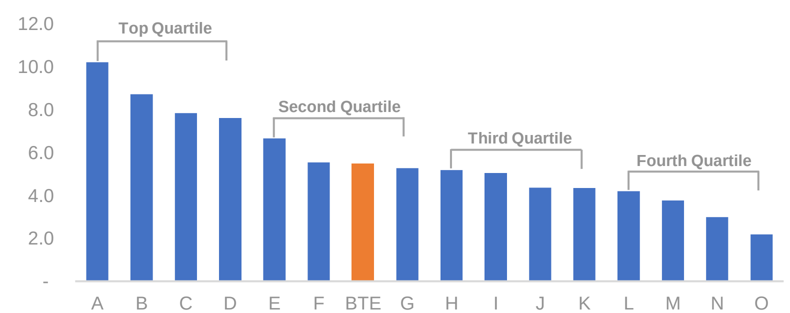
Average Lateral Length (feet) by Eagle Ford Operator[1][3] – Last 15 Months



Average of First 3 Months Production by Eagle Ford Operator – Last 15 Months
Crude Oil (bbl)[1][2]



Average of First 3 Months Production by Eagle Ford Operator – Last 15 Months
Crude Oil (bbl/feet) [1][2]



(1) Data set (total of 1,169 wells) includes: Baytex, ConocoPhillips, Crescent, Devon, EOG, Exxon, Gulftex, Magnolia, Marathon, Repsol, Ridgemar, SM Energy, Trinity, Verdun, Warwick Partners, Wildfire.
(2) Source: Enverus, Baytex internal data.

CANADA LIGHT OIL: PEMBINA DUVERNAY / VIKING

High netback light oil with strong asset level free cash flow(1)

Pembina Duvernay Shale is a potential growth asset in the Canadian portfolio

Pembina Duvernay

142 net sections

Demonstration-stage light oil resource play

Produced **7,550 boe/d** in Q3/2024 (83% liquids)

9 net wells onstream in 2025

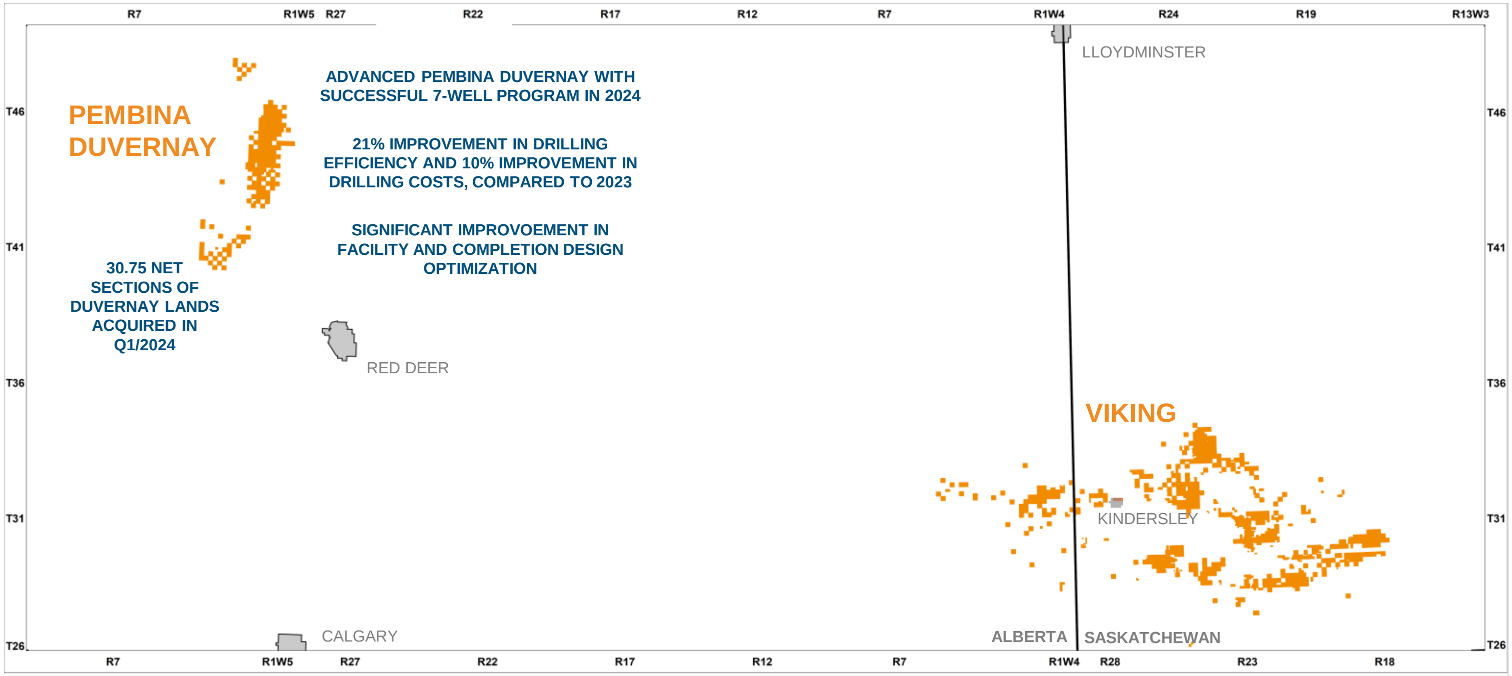
Viking

344 net sections

Stable production and meaningful asset level free cash flow

Produced **11,000 boe/d** in Q3/2024 (86% liquids)

Expect to bring **~ 90 net wells** onstream in 2025



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CANADA HEAVY OIL: PEACE RIVER / PEAVINE / LLOYDMINSTER

Innovative Multi-Lateral Drilling and Top-Tier Efficiencies

Clearwater at Peavine Delivers Exceptional Well Performance and Economics

Peace River (Bluesky)

514 net sections

Produced **11,100 boe/d** in Q3/2024 (82% oil)

Expect to bring **13 net MLHZ wells** onstream in 2025

Peavine (Clearwater)

Partnership with Peavine Métis Settlement covering **90 contiguous sections**

Produced **20,100 boe/d** in Q3/2024 (100% oil)

Expect to bring **33 net MLHZ wells** onstream in 2025

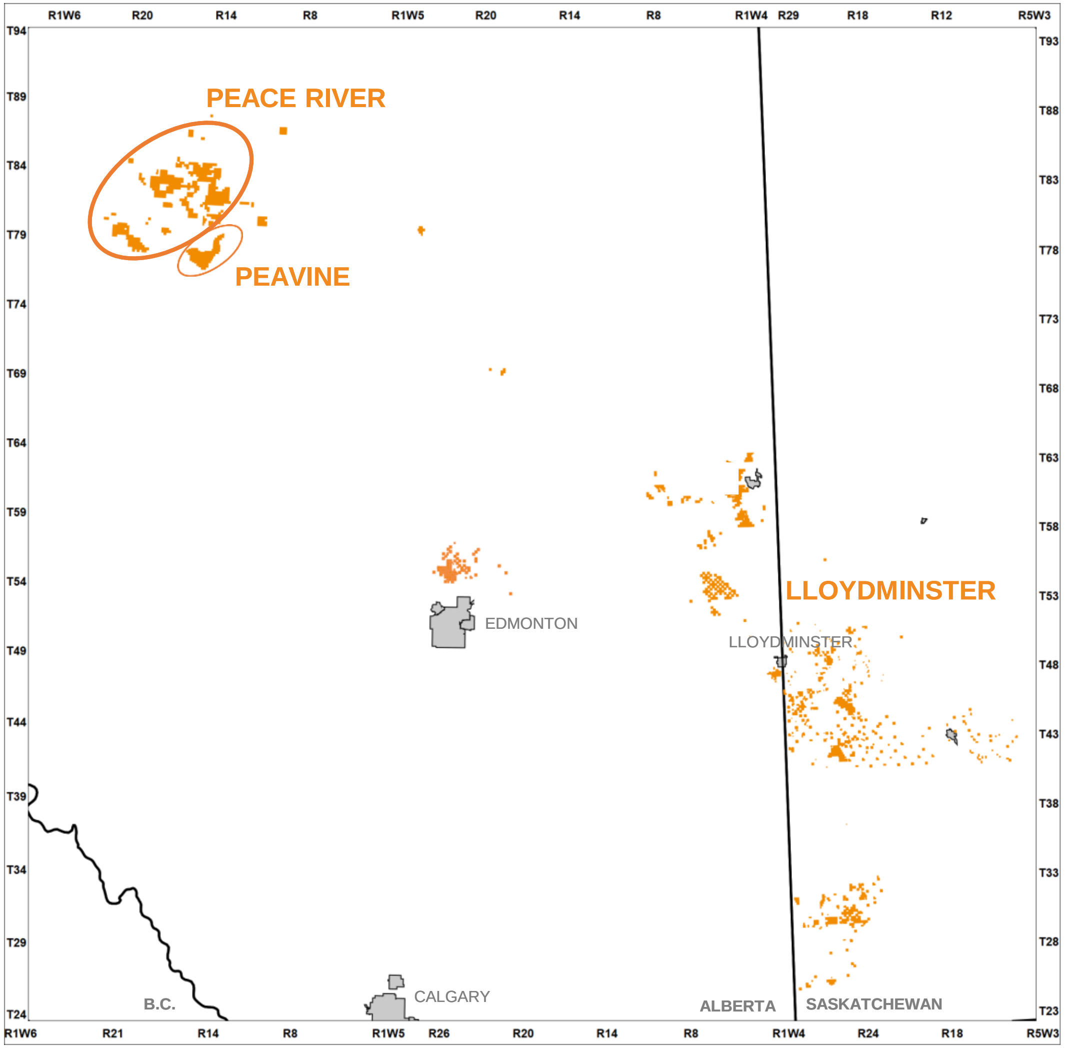
Lloydminster (Mannville)

516 net sections

Produced **13,100 boe/d** in Q3/2024 (98% oil)

Targeting multiple horizons within the Mannville group of formations

Expect to bring **~ 61 net wells** onstream in 2025



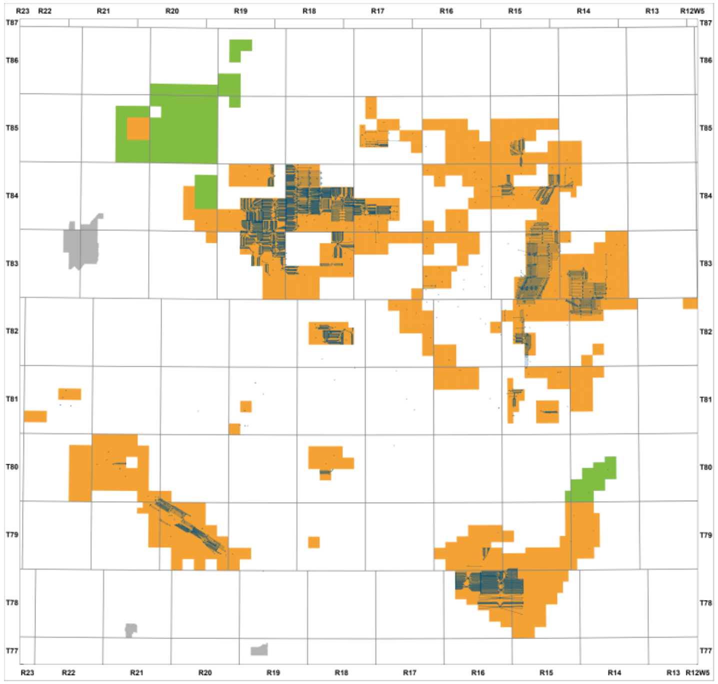
CANADA HEAVY OIL: LAND EXTENSIONS

Leveraging heavy oil expertise and recent exploration success

Peace River (Clearwater + Bluesky)

10-section agreement with the Peavine Métis Settlement brings total land position to 90 sections prospective for Clearwater development

Farm-in agreement on 66 sections of land near Peace River with prospectivity for the Bluesky formation

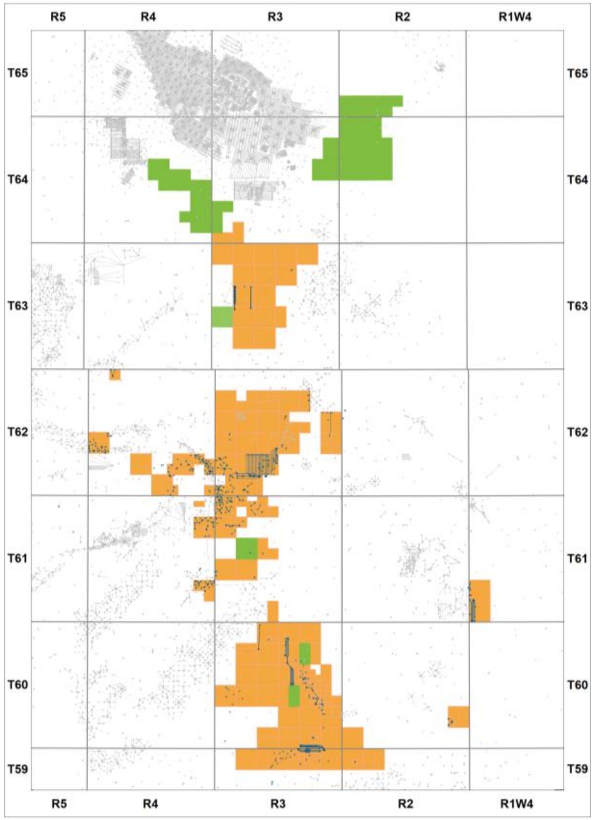


Baytex legacy lands   Recent land agreements

Lloydminster (Mannville)

Farm-in agreement on 17.75 sections of land near Cold Lake

Increases lands prospective for **Mannville development** in northeast Alberta to ~ 100 sections



SUPPLEMENTARY INFORMATION

BOARD OF DIRECTORS

Efficient and Independent Board

Complementary Skills Suited to Govern the Combined Business

Eric T. Greager
President and CEO

Mark R. Bly
Chair of the Board

Tiffany ("T.J.") Cepak

Trudy M. Curran

Don G. Hrap

Angela Lekatsas

Jennifer A. Maki

Dave L. Pearce

Steve D.L. Reynish

Jeffrey E. Wojahn

10 board members, 9 of which are independent

FREE CASH FLOW ALLOCATION POLICY

Direct shareholder returns at 50% of free cash flow[1]

Total Debt[2] Above $1.5 billion

Adjusted Funds Flow[3]

Less: Exploration and Development Expenditures

Less: Abandonment and Reclamation / Leasing Expenditures

Free Cash Flow

50%
Balance Sheet

50%
Direct Shareholder Return

Share Repurchases

Base Dividend

Total Debt Below $1.5 billion

Shareholder returns increase to **75% of free cash flow**

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(2) Calculated in accordance with the amended credit facilities agreement which is available on the SEDAR+ website at www.sedarplus.ca.

(3) Capital management measure. Refer to the Capital Management Measures Advisory section in this presentation for further information.

SUMMARY OF OPERATING AND FINANCIAL METRICS

	Q1 2023	Q2 2023	Q3 2023	Q4 2023	2023	Q1 2024	Q2 2024	Q3 2024
Benchmark Prices								
WTI crude oil (US$/bbl)	$76.13	$73.78	$82.26	$78.32	**$77.62**	$76.96	$80.57	$75.10
NYMEX natural gas (US$/MMbtu)	$3.42	$2.10	$2.55	$2.88	**$2.74**	$2.24	$1.89	$2.16
Production								
Crude oil (bbl/d)	65,869	68,143	110,967	109,693	**88,849**	106,596	110,734	112,602
Natural gas liquids (bbl/d)	7,213	8,620	18,004	23,160	**14,304**	19,299	20,167	19,836
Natural gas (mcf/d)	82,066	77,989	129,780	165,121	**114,010**	148,353	139,764	132,175
Oil equivalent (boe/d) [1]	86,760	89,761	150,600	160,373	**122,154**	150,620	154,194	154,468
% Liquids	84%	86%	86%	83%	**84%**	84%	84%	86%
Netback ($/boe)								
Total sales, net of blending and other expenses [2]	$63.48	$66.82	$80.34	$68.00	**$70.82**	$67.12	$75.93	$71.97
Royalties [3]	(11.94)	(13.21)	(17.33)	(15.49)	**(15.02)**	(15.26)	(17.14)	(15.75)
Operating expense [3]	(14.40)	(14.62)	(12.57)	(11.17)	**(12.80)**	(12.65)	(11.95)	(11.76)
Transportation expense [3]	(2.18)	(1.78)	(2.02)	(2.02)	**(2.00)**	(2.18)	(2.37)	(2.60)
Operating Netback [2]	$34.96	$37.21	$48.42	$39.32	**$41.00**	$37.03	$44.47	$41.86
General and administrative [3]	(1.50)	(1.87)	(1.48)	(1.51)	**(1.57)**	(1.64)	(1.50)	(1.26)
Cash financing and interest [3]	(2.35)	(3.46)	(4.08)	(3.84)	**(3.58)**	(3.89)	(3.84)	(3.53)
Realized financial derivative gain (loss) [3]	(0.69)	2.00	0.15	0.84	**0.81**	0.40	(0.16)	0.02
Other [4]	(1.45)	(0.39)	(1.03)	(0.77)	**(0.90)**	(0.98)	(1.00)	0.76
Adjusted funds flow [5]	**$30.35**	**$33.49**	**$41.98**	**$34.03**	**$35.76**	**$30.92**	**$37.97**	**$37.85**

(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 Advisory section in this presentation for further information.

(3) Supplementary financial measure calculated as royalties, operating, transportation, general and administrative, cash interest expense or realized financial derivative gain (loss) divided by barrels of oil equivalent production volume for the applicable period.

(4) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and share based compensation. Refer to the Q3 2024 MD&A available on the SEDAR+ website at www.sedarplus.ca for further information on these amounts.

(5) Capital management measure. Refer to the Capital Management Measures Advisory section in this presentation for further information.

2025 GUIDANCE AND COST ASSUMPTIONS

Exploration and development expenditures ($ billions)	$1.2 - $1.3
Production (boe/d)	148,000 - 152,000
Expenses:	
Average royalty rate (%) (1)	~ 23%
Operating ($/boe) (2)	$11.75 - $12.50
Transportation ($/boe) (2)	$2.40 - $2.55
General and administrative ($ millions) (2)	$90 ($1.62/boe)
Interest ($ millions) (2)	$180 ($3.24/boe)
Current Income Taxes ($ millions) (2)	~ 1% of EBITDA(3)
Leasing expenditures ($ millions)	$10
Asset retirement obligations ($ millions)	$25

(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 Advisory section in this presentation for further information.
(2) Supplementary financial measure calculated as operating, transportation, general and administrative or cash interest expense divided by barrels of oil equivalent production volume for the applicable period.
(3) Calculated in accordance with the amended credit facilities agreement which is available on the SEDAR+ website at www.sedarplus.ca.

2025 ADJUSTED FUNDS FLOW SENSITIVITIES

Sensitivities	Estimated Effect on Annual Adjusted Funds Flow[(1)(2)] ($MM)
Change of US$5.00/bbl WTI crude oil	$225
Change of US$1.00/bbl WCS heavy oil differential	$12
Change of US$0.50/MMbtu NYMEX natural gas	$17
Change of $0.01 in the C$/US$ exchange rate	$18

(1) Capital management measure. Refer to the Capital Management Measures Advisory section in this presentation for further information.
(2) Includes the impact of 2025 commodity hedging program.

FORWARD LOOKING STATEMENTS ADVISORY

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

Specifically, this presentation contains forward-looking statements relating to but not limited to: expectations for 2025 as to Baytex’s production on a boe/d basis, percentage of production that will be liquids, exploration and development expenditures and our expected production by area and commodity; that we prioritize free cash flow; that we have more than 10 years of drilling inventory; the allocation of free cash flow, including with respect to debt repayment, share buybacks and dividends; for 2025 our expected: production, percentage of production that will be liquids, the number of net wells onstream, exploration and development expenditures, 2025 priorities, production growth; expectations for 2025 free cash flow at prices of US$65 WTI, US$75 WTI and US$85 WTI; expectations regarding the quarterly dividend; that we are committed to a strong balance sheet and that our $1.5 billion total debt target represents ~0.7x total debt to EBITDA at US$70 WTI; our hedging plans, including our target to hedge up to 45% of net crude volumes, that we intend to utilize wide 2-way collars to ensure a modest return on our highest breakeven assets and the percentage of our expected production that is hedged until the end of Q4/2025; with respect to our five-year outlook, our production growth rate, the expectation that we will prioritize free cash flow, that we target a total debt to EBITDA ratio of less than 1.0x, increase in production per share and free cash flow per share, free cash flow at specified prices for WTI, share buybacks and dividends at specified prices for WTI; for 2025 the expected production rate, percentage of production that will be liquids and percentage contribution to asset level free cash flow, and the expected individual well CROCI, payout and IRR for expected type wells for our business units; the expected number of net wells to sales for our assets in 2025; that we have 90 section prospective for Clearwater development at Peavine and ~100 sections prospective for Mannville development in NE Alberta; our free cash flow allocation policy; our 2025 guidance, including: our expected exploration and development expenditures, production, average royalty rate, expenses (operating, transportation, general and administrative, interest costs and current income taxes), leasing expenditures and asset retirement obligations; and the sensitivity of our annual adjusted funds flow to changes in WTI prices, WCS, NYMEX natural gas prices and the Canada-United States foreign exchange rate. 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.

FORWARD LOOKING STATEMENTS ADVISORY (CONT.)

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; success obtained in drilling new wells; our ability to add production and reserves through our exploration and development activities; that our core assets have more than 10 years development inventory at the current pace of development; 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, including operating and transportation costs; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our hedging program; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; timing and amount of capital expenditures; our future costs of operations are as anticipated; the timing of drilling and completion of wells is as anticipated; that we will have sufficient cash flow, debt or equity sources or other financial resources required to fund our capital and operating expenditures and requirements as needed; that our conduct and results of operations will be consistent with our expectations; that we will have sufficient financial resources in the future to allocate to 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; 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.

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, filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission and in our other public filings. The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

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

FORWARD LOOKING STATEMENTS ADVISORY (CONT.)

Financial Outlook Advisory

This presentation contains information that may be considered a financial outlook under applicable securities laws about Baytex's potential financial position, including, but not limited to, estimated EBITDA, exploration and development expenditures, allocation of free cash flow to shareholder returns, total debt to adjusted EBITDA, free cash flow and adjusted funds flow, and the dividend payable by Baytex, all of which are subject to numerous assumptions, risk factors, limitations and qualifications, including those set forth herein. The actual results of operations of Baytex will vary from the amounts set forth in this presentation 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, Baytex undertakes no obligation to update such financial outlook. The financial outlook contained in this press release was made as of the date of this press release and was provided for the purpose of providing further information about Baytex's potential future business operations. Readers are cautioned that the financial outlook contained in this presentation is not conclusive and is subject to change.

Share Buyback Advisory

The future acquisition by Baytex of its shares pursuant to a share buyback program, if any, and the level thereof is uncertain. Any decision to acquire shares of Baytex will be subject to the discretion of the Baytex Board of Directors 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, satisfaction of the solvency tests imposed on Baytex under applicable corporate law and receipt of regulatory approvals. There can be no assurance that Baytex will buyback any shares of Baytex in the future.

Dividend Advisory

Future 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) 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.

SPECIFIED FINANCIAL MEASURES ADVISORY

In this presentation, we refer to certain specified financial measures which do not have any standardized meaning prescribed by International Financial Reporting Standards ("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. There are no significant differences in the calculations between historical and forward-looking specified financial measures.

Non-GAAP Financial Measures

Free cash flow

Free cash flow in this presentation may refer to a forward-looking non-GAAP measure that is calculated consistently with the measures disclosed in the Company's MD&A. The most directly comparable financial measure for free cash flow disclosed in the Company's primary financial statements is cash flows from operating activities. For the three months ended September 30, 2024, cash flows from operating activities was $550 million and free cash flow was $220 million. For the nine months ended September 30, 2024, cash flows from operating activities was $1.4 billion and free cash flow was $401 million. For information on the composition of free cash flow and how the Company uses this measure, refer to the "Specified Financial Measures" section of the MD&A for the three and nine months ended September 30, 2024, which is incorporated herein by reference, and available on the SEDAR+ website at www.sedarplus.ca.

Asset level free cash flow

Asset level free cash flow represents the free cash flow for a set of assets and is used to assess the operating performance of a specific business unit. Asset level free cash flow is calculated the same as free cash flow, with the exclusion of corporate costs. This measure is comprised of petroleum and natural gas sales, adjusted for blending expense, royalties, operating expense, transportation expense, additions to exploration and evaluation assets, additions to oil and gas properties and asset retirement obligations settled.

Operating netback

The most directly comparable financial measure for operating netback disclosed in the Company's primary financial statements is petroleum and natural gas sales. For the three months ended September 30, 2024, petroleum and natural gas sales were $1.1 billion and operating netback was $595 million. For the nine months ended September 30, 2024, petroleum and natural gas sales were $3.2 billion and operating netback was $1.7 billion. For information on the composition of operating netback and how the Company uses this measure, refer to the "Specified Financial Measures" section of the MD&A for the three and nine months ended September 30, 2024, which is incorporated herein by reference, and available on the SEDAR+ website at www.sedarplus.ca.

Total sales, net of blending and other expense

Total sales, net of blending and other expense may refer to a forward-looking non-GAAP measure that is calculated consistently with the measures disclosed in the Company's MD&A. The most directly comparable financial measure for total sales, net of blending and other expense disclosed in the Company's primary financial statements is petroleum and natural gas sales. For the three months ended September 30, 2024, petroleum and natural gas sales were $1.1 billion and total sales, net of blending and other expense were $1.0 billion. For the nine months ended September 30, 2024, petroleum and natural gas sales were $3.2 billion and total sales, net of blending and other expense were $3.0 billion. For information on the composition of total sales, net of blending and other expense and how the Company uses these measures, refer to the "Specified Financial Measures" section of the MD&A for the three and nine months ended September 30, 2024, which is incorporated herein by reference, and available on the SEDAR+ website at www.sedarplus.ca.

Return of capital

Return of capital is comprised of dividends declared and the consideration paid for the repurchase and cancellation of common shares and is used to measure the amount of capital returned to shareholders during a given period. Return of capital in this presentation may refer to a forward-looking non-GAAP measure and is calculated consistently with the historical return of capital. Historical return of capital for the three and nine months ended September 30, 2024 and 2023 is calculated below.

	Three Months Ended September 30		Nine Months Ended September 30	
($ thousands)	**2024**	2023	**2024**	2023
Dividends declared	**$ 17,732**	$ 19,138	**$ 54,387**	$ 19,138
Repurchases of common shares	**84,573**	89,266	**168,468**	89,266
Return of Capital	**102,305**	108,404	**222,855**	108,404

Non-GAAP Financial Ratios

Free cash flow per share

Free cash flow per share is calculated as free cash flow at an assumed WTI price divided by the number of shares outstanding during the applicable period. This measure is used by management to compare against earnings per share metrics. There are no significant differences in calculations between historical and forward-looking specific financial measures.

Average royalty rate

Average royalty rate is used calculated as royalties divided by total sales, net of blending and other expense which is a non-GAAP measure.

CAPITAL MANAGEMENT MEASURES ADVISORY

This presentation contains the terms "adjusted funds flow“ and "net debt”, which are capital management measures. We believe that the inclusion of these capital management measures provides useful information to financial statement users when evaluating the financial results of Baytex. Net debt and adjusted funds flow are calculated consistently with the measures disclosed in the Company’s MD&A. The most directly comparable financial measures for net debt and adjusted funds flow disclosed in the Company's primary financial statements are credit facilities and cash flows from operating activities, respectively. As at September 30, 2024, credit facilities were $449 million. For the three and nine months ended September 30, 2024, cash flows from operating activities were $550 million and $1.4 billion, respectively.

As at September 30, 2024, net debt was $2.5 billion. For the three and nine months ended September 30, 2024, adjusted funds flow was $538 million and $1.5 billion, respectively. For information on the composition of these measures and how the Company uses them, refer to the “Specified Financial Measures” section of the MD&A for the three and nine months ended September 30, 2024, which is incorporated herein by reference, and available on the SEDAR+ website at www.sedarplus.ca.

ADVISORY REGARDING OIL AND GAS INFORMATION

The reserves information contained in this presentation has been prepared in accordance with National Instrument 51-101 -Standards of Disclosure for Oil and Gas Activities of the Canadian Securities Administrators ("NI 51-101"). The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts, including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods, is required to properly use and apply reserves definitions.

The recovery and reserves estimates described herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves and future production from such reserves may be greater or less than the estimates provided herein. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. Complete NI 51-101 reserves disclosure for year-end 2023 is included in our Annual Information Form for the year ended December 31, 2023 which has been filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

This presentation discloses drilling inventory and potential drilling locations. Drilling inventory and drilling locations refers to Baytex's total 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.

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.

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

Notice to United States Readers

The petroleum and natural gas reserves contained in this presentation 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, NI51-101 defines "proved reserves" and "probable reserves" differently from the SEC rules. Accordingly, proved and probable reserves disclosed in this presentation 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 presentation may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

CONTACT INFORMATION

BAYTEX ENERGY CORP.

Suite 2800, Centennial Place
520 – 3rd Avenue S.W.
Calgary, Alberta T2P 0R3

TF 1.800.524.5521

Eric T. Greager
President and Chief Executive Officer

Chad L. Kalmakoff
Chief Financial Officer

Chad E. Lundberg
Chief Operating Officer

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

587.952.3237

BAYTEXENERGY.COM

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