



# INVESTOR PRESENTATION

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

SEPTEMBER 2025





# ADVISORY

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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.

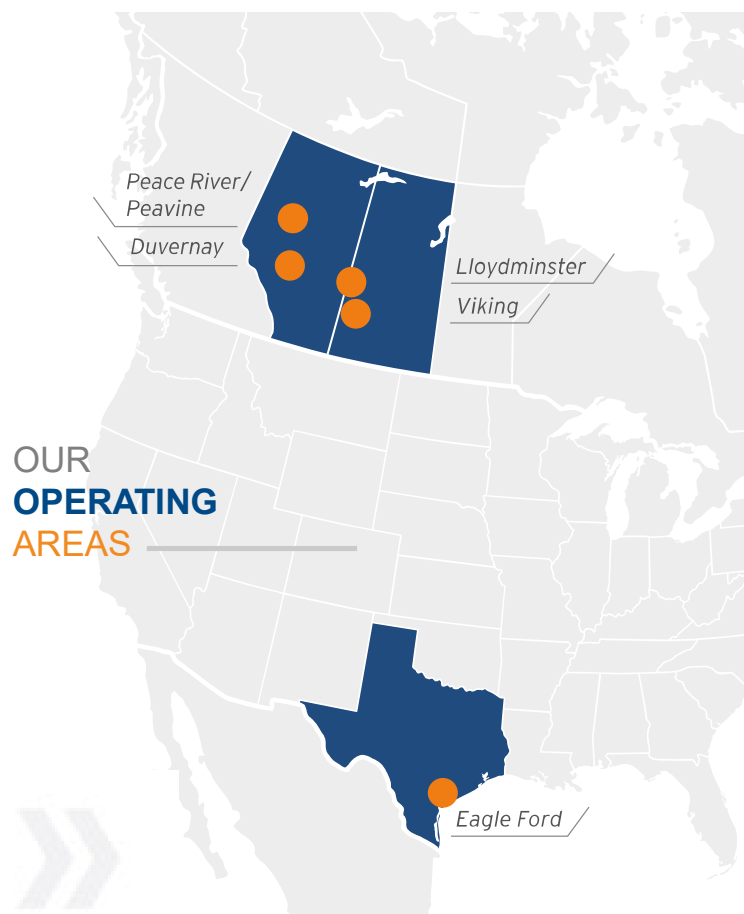
All slides in this presentation should be read in conjunction with “Forward Looking Statements Advisory”, “Specified Financial Measures Advisory”, “Capital Management Measures Advisory” and “Advisory Regarding Oil and Gas Information”.

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 June 30, 2025.

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 September 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



## Market Summary

|                                                              |                                     |
|--------------------------------------------------------------|-------------------------------------|
| Ticker Symbol                                                | TSX, NYSE   BTE                     |
| Average Daily Volume <sup>(1)</sup>                          | Canada: 10 million   US: 19 million |
| Shares Outstanding <sup>(2)</sup>                            | 768 million                         |
| Market Capitalization / Enterprise Value <sup>(3)</sup>      | \$2.3 billion / \$4.6 billion       |
| Annual Dividend per Share   Dividend Yield <sup>(4)(5)</sup> | \$0.09   3.0%                       |

## Operating Statistics

|                                              |                 |
|----------------------------------------------|-----------------|
| Production (working interest) <sup>(6)</sup> | ~ 148 Mboe/d    |
| Production Mix <sup>(6)</sup>                | 85% liquids     |
| E&D Expenditures <sup>(6)</sup>              | ~ \$1.2 billion |
| Reserves – 2P Gross <sup>(7)</sup>           | 660 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 August 2025. Volumes are a composite of all exchanges.

(2) Shares outstanding as at August 29, 2025.

(3) Enterprise value based on closing share price on the Toronto Stock Exchange on August 29, 2025 and net debt as at June 30, 2025. 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 Advisory section in this presentation for further information.

(4) Refer to the Dividend Advisory section in this 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. Production guidance range: 148,000 to 152,000 boe/d. E&D expenditures range \$1.2 to \$1.3B.

(7) Baytex's year-end 2024 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 "Advisory Regarding Oil and Gas Information".

## INVESTMENT HIGHLIGHTS

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



### Disciplined Reinvestment and Capital Allocation

Prioritizing free cash flow<sup>(1)</sup>

High-quality oil-weighted portfolio with more than 10-years of drilling inventory

Track record of new discoveries



### Shareholder Returns

Prioritizing balance sheet in the near-term

Annual dividend of \$0.09 per share (declared quarterly)

Repurchased 11% of shares outstanding since June 2023



### Financial Position

Significant credit capacity

Long-term notes termed out to 2030 and 2032

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.

## H1/2025 HIGHLIGHTS

# Delivered solid results with record Pembina Duvernay well performance and continued debt reduction



### Strong Execution

Operating and financial results in line with full-year plan  
2% increase in production per share in Q2/2025, compared to Q2/2024  
Net debt<sup>(1)</sup> reduced 5% (\$123 million)



### Pembina Duvernay Performance

Achieved record well performance with first pad (3-wells) delivering average peak 30-day initial rates of 1,865 boe/d per well (89% oil and NGL)  
12% improvement in drilling and completion costs per completed lateral foot, compared to 2024



### Eagle Ford Development

27 net wells onstream, realizing an 11% improvement in drilling and completion costs per completed lateral foot, compared to 2024  
Two successful refracs, extending inventory duration and improving capital efficiencies



### Heavy Oil Program

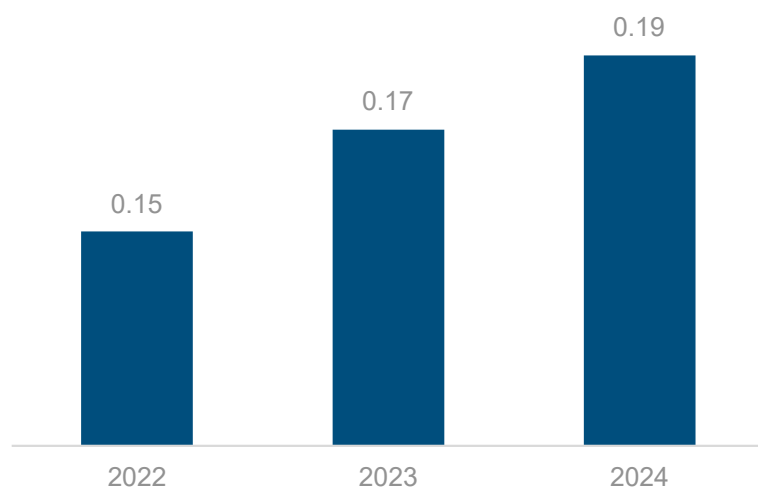
Production increased 7% in Q2/2025, compared to Q1/2025  
Continued performance at Peavine, Peace River and Lloydminster  
Delivers strongest economic return across portfolio

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

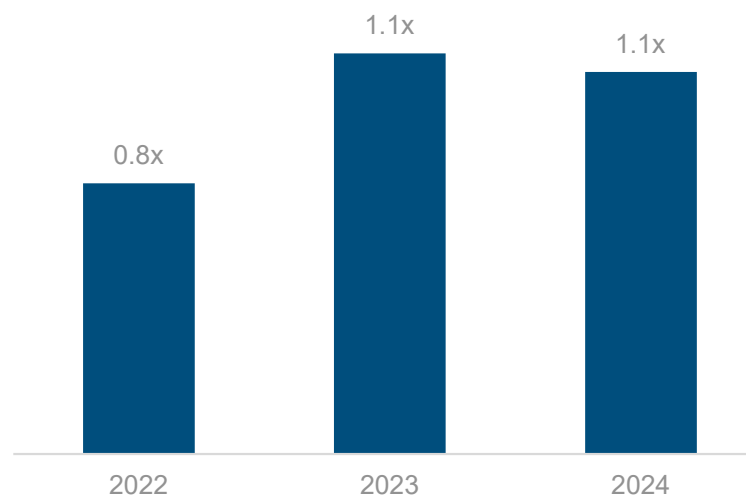
# CREATING SHAREHOLDER VALUE

## Production per share growth with reasonable leverage

Production (boe/d) per thousand shares



Total debt<sup>(1)</sup> to Bank EBITDA<sup>(1)(2)</sup>



(1) Calculated in accordance with the amended credit facilities agreement which is available on the SEDAR+ website at [www.sedarplus.ca](http://www.sedarplus.ca).

(2) Total Debt to Bank EBITDA ratio based on year-end total debt and trailing 12-month Bank EBITDA.

# 2025 OUTLOOK



## Disciplined Reinvestment and Capital Allocation

### Prioritizing free cash flow<sup>(1)</sup>

Moderating growth profile and delivering **stable production**

**Strong drilling, completion and operating performance** across portfolio

Operationally efficient development in the Eagle Ford

Advance Pembina Duvernay

Capital efficient heavy oil development



**~ 148,000 boe/d**  
2025 production

### 2025 Guidance <sup>(2)</sup>

|                  |                 |
|------------------|-----------------|
| E&D Expenditures | ~ \$1.2 billion |
| Production       | ~ 148,000 boe/d |
| Oil and NGLs     | 85%             |

| Operating Area                  | Net Wells Onstream | E&D Expenditures (\$MM) |
|---------------------------------|--------------------|-------------------------|
| U.S. Light Oil <sup>(2)</sup>   | 50                 | \$680                   |
| Canada Light Oil <sup>(3)</sup> | 94                 | \$265                   |
| Canada Heavy Oil <sup>(4)</sup> | 120                | \$255                   |
| Total                           | 264                | \$1,200                 |

(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 production guidance range: 148,000 to 152,000 boe/d. E&D expenditures range \$1.2 to \$1.3B.

(3) U.S. Light Oil includes operated / non-operated Eagle Ford.

(4) Canada Light Oil includes Duvernay / Viking.

(5) Canada Heavy Oil includes Peace River (Bluesky) / Peavine (Clearwater) / Lloydminster (Mannville).



## 2025 RETURN OF CAPITAL

# Shareholder return framework to prioritize balance sheet



## Free Cash Flow Priorities

Strengthening Balance Sheet

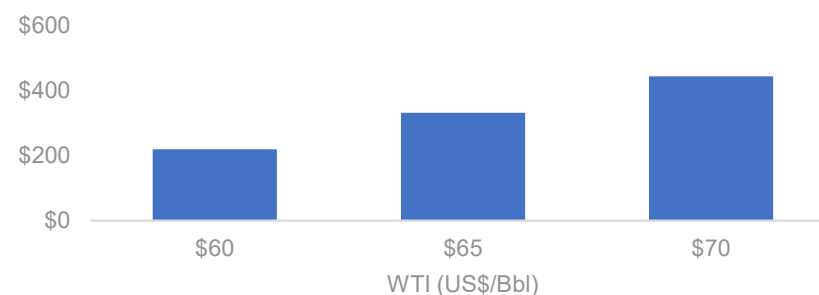
### Near-term

100% of free cash flow to debt repayment after funding quarterly dividend

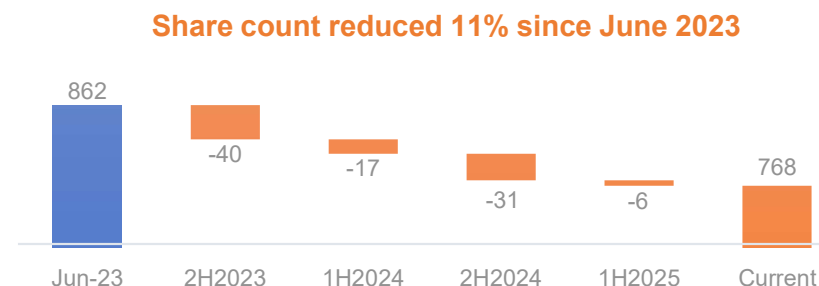
### Long-term

Maintain a prudent approach to shareholder returns, which has historically comprised a mix of share buybacks and quarterly dividends

2025 Free Cash Flow (\$ millions)<sup>(1)(2)</sup>



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 2025 guidance and incorporates H1 2025 actual results and balance of year WTI prices of US\$60/bbl, US\$65/bbl and US\$70/bbl, and the following commodity price assumptions: WCS differential – US\$12/bbl; NYMEX Gas - US\$3.75/MMbtu; Exchange Rate (CAD/USD) – 1.35.



## MAINTAINING FINANCIAL STRENGTH

# Commitment to a Strong Balance Sheet



### Significant credit capacity

### Resilient through the commodity price cycles

### Strong long-term notes maturity schedule

Less than 25% drawn on US\$1.1B of total credit facilities

Repurchased and cancelled US\$41 million of 2030 long-term notes in 2025

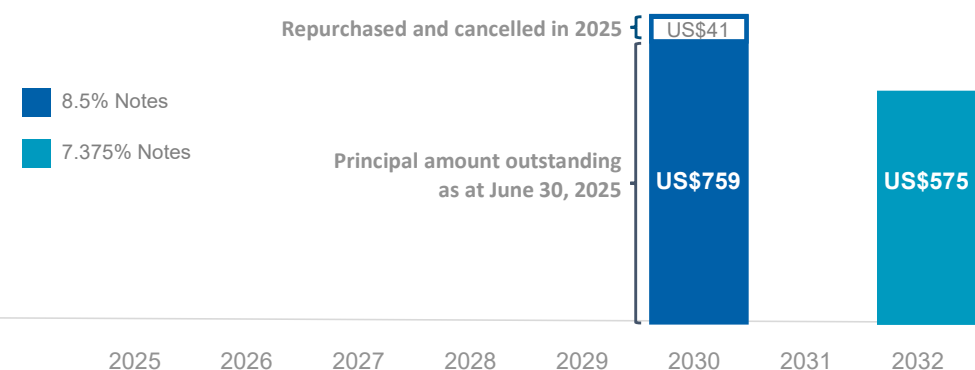
Total debt<sup>(2)</sup> target of \$1.5 billion (~ 0.7x total debt to EBITDA<sup>(2)</sup> at US\$70 WTI)

### Total Debt <sup>(1)(2)</sup>

C\$ millions

|                                  |         |
|----------------------------------|---------|
| Credit facilities <sup>(3)</sup> | \$333   |
| Long-term notes                  |         |
| 8.500% notes due April 1, 2030   | \$1,035 |
| 7.375% notes due April 1, 2032   | \$783   |
| Total long-term notes            | \$1,818 |
| Total debt                       | \$2,151 |

### Long-Term Notes Maturity Schedule (US\$ millions)



(1) Total debt as at June 30, 2025.

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

(3) Revolving credit facilities total US\$1.1 billion and mature June 2029. The revolving credit facilities are not borrowing base facilities and do not require annual or semi-annual reviews.

# CRUDE OIL HEDGE PORTFOLIO

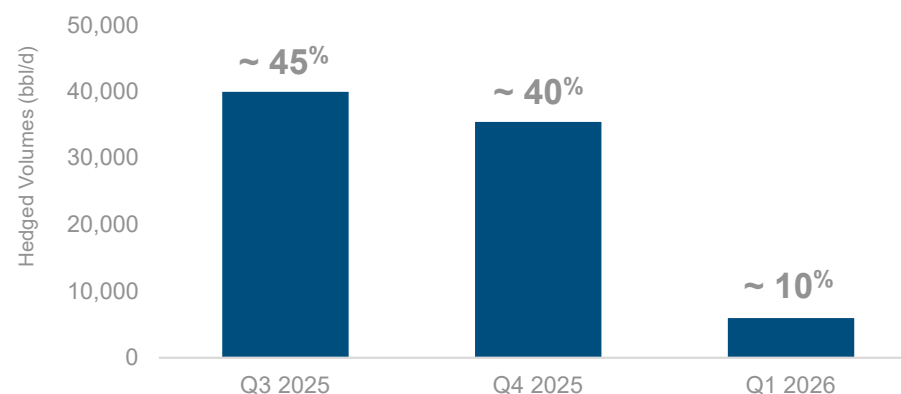
## Balanced Approach to Risk Management



**Target up to 45% of  
Net Crude Oil  
Volumes<sup>(1)</sup>**

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

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



Collars  
(Weighted Average)

|                |         |         |         |
|----------------|---------|---------|---------|
| Ceiling (US\$) | \$80.00 | \$80.00 | \$75.28 |
| Floor (US\$)   | \$60.00 | \$60.00 | \$60.00 |

(1) Percentage of hedged volumes are based on 2025 production guidance (excluding NGLs), net of royalties.



## FIVE-YEAR OUTLOOK (2024 – 2028)

### Sustainable plan<sup>(1)(2)</sup> delivers significant value



#### Prioritizing free cash flow<sup>(3)</sup>

Balance sheet, quarterly dividend, share buybacks



#### 0-4% annual production growth

Base plan delivers stable production; optionality for organic growth under higher commodity prices



#### Strong economics across portfolio

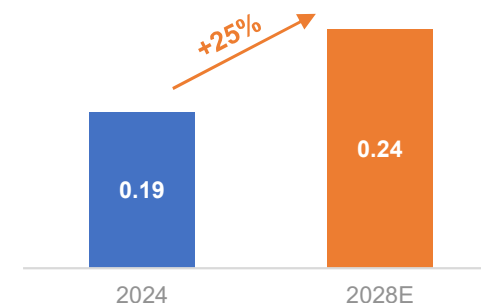
> 10 years of drilling inventory



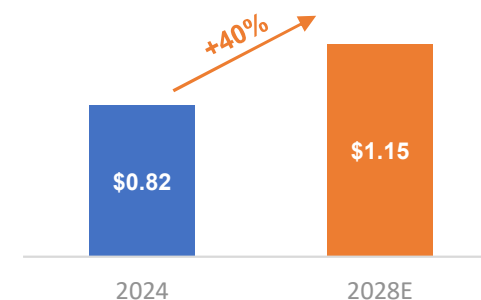
#### Balance sheet strength

Target total debt<sup>(4)</sup> to Bank EBITDA<sup>(4)</sup> ratio < 1.0x

Production  
(boe/d per thousand shares)



Free Cash Flow (per share)<sup>(3)</sup>



(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 actual results. Year two (2025) based on 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 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](http://www.sedarplus.ca).





## FIVE-YEAR OUTLOOK (2024 – 2028)

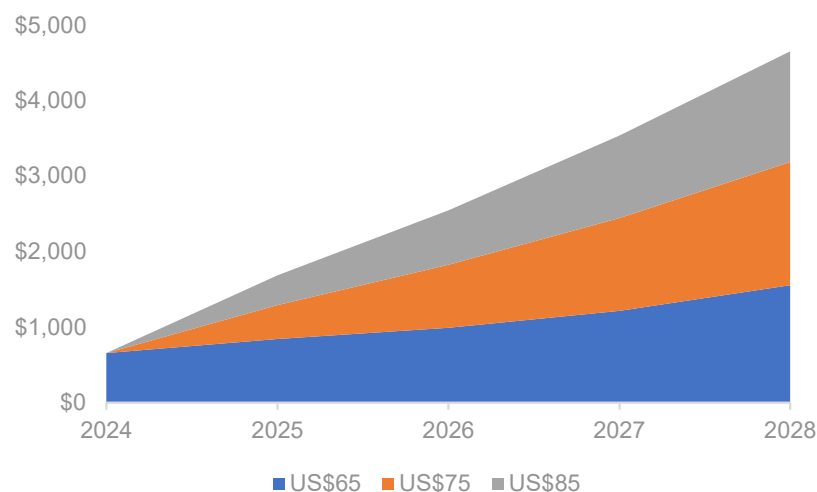
### Shareholder Returns<sup>(1)(2)</sup>



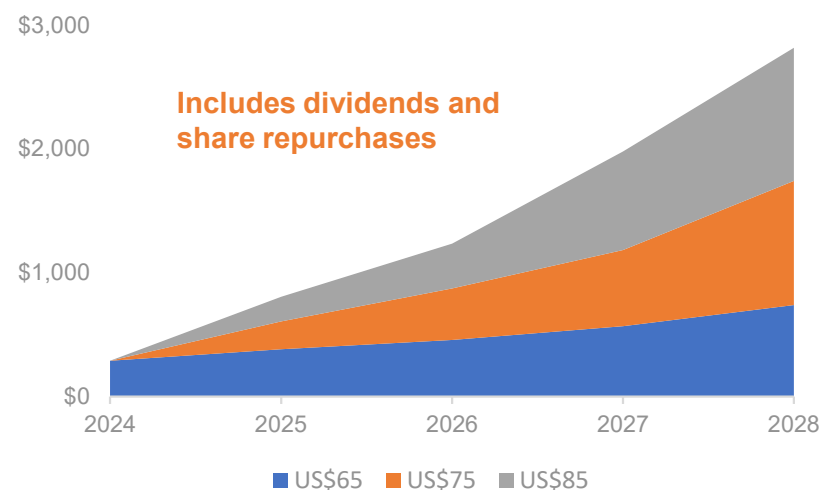
#### Compelling Returns Profile

Underpinned by disciplined reinvestment and capital allocation

Free Cash Flow<sup>(3)</sup> over Five-Year Outlook (\$ millions)



Return of Capital<sup>(3)</sup> 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 actual results. Year two (2025) based on 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 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

NYSE | TSX | BTE

BAYTEXENERGY.COM

# BUSINESS UNIT HIGHLIGHTS



|                                                                   | Light Oil – USA<br>(Eagle Ford) | Light Oil – Canada<br>(Viking/Duvernay) | Heavy Oil – Canada<br>(Peace River/Peavine/<br>Lloydminster) |
|-------------------------------------------------------------------|---------------------------------|-----------------------------------------|--------------------------------------------------------------|
| <b>Production (2025E)</b>                                         | 82,000 boe/d                    | 18,000 boe/d                            | 44,000 boe/d                                                 |
| <b>% Liquids</b>                                                  | 81%                             | 83%                                     | 96%                                                          |
| <b>Land (net acres)</b>                                           | 178,000                         | 317,000                                 | 745,000                                                      |
| <b>2P Reserves (Gross) <sup>(1)</sup></b>                         | 401 MMboe                       | 109 MMboe                               | 137 MMboe                                                    |
| <b>Asset Level Free Cash Flow (% of corporate) <sup>(2)</sup></b> | 55%                             | 5%                                      | 40%                                                          |
| <b>Drilling Locations (net risked) <sup>(3)</sup></b>             | ~ 800                           | ~ 1,200                                 | ~ 900                                                        |
| <b>Individual Well Economics <sup>(4) (5)</sup></b>               |                                 |                                         |                                                              |
| <b>IRRs</b>                                                       | 45% to 90%                      | 55% to 90%                              | 95% to > 250%                                                |
| <b>Payouts</b>                                                    | 14 to 26 months                 | 14 to 21 months                         | 8 to 13 months                                               |
| <b>CROCI <sup>(6)</sup></b>                                       | 2.1x to 2.5x                    | 2.0x to 2.7x                            | 2.4x to 4.0x                                                 |

(1) Baytex's year-end 2024 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 "Advisory Regarding Oil and Gas Information".

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(3) Net locations includes proved plus probable undeveloped reserves locations at year-end 2024 and unbooked future locations. See "Advisory Regarding Oil and Gas Information".

(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

**255,000 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 50 net wells to sales (~ 75% operated) in 2025

### 2025 Operated Activity

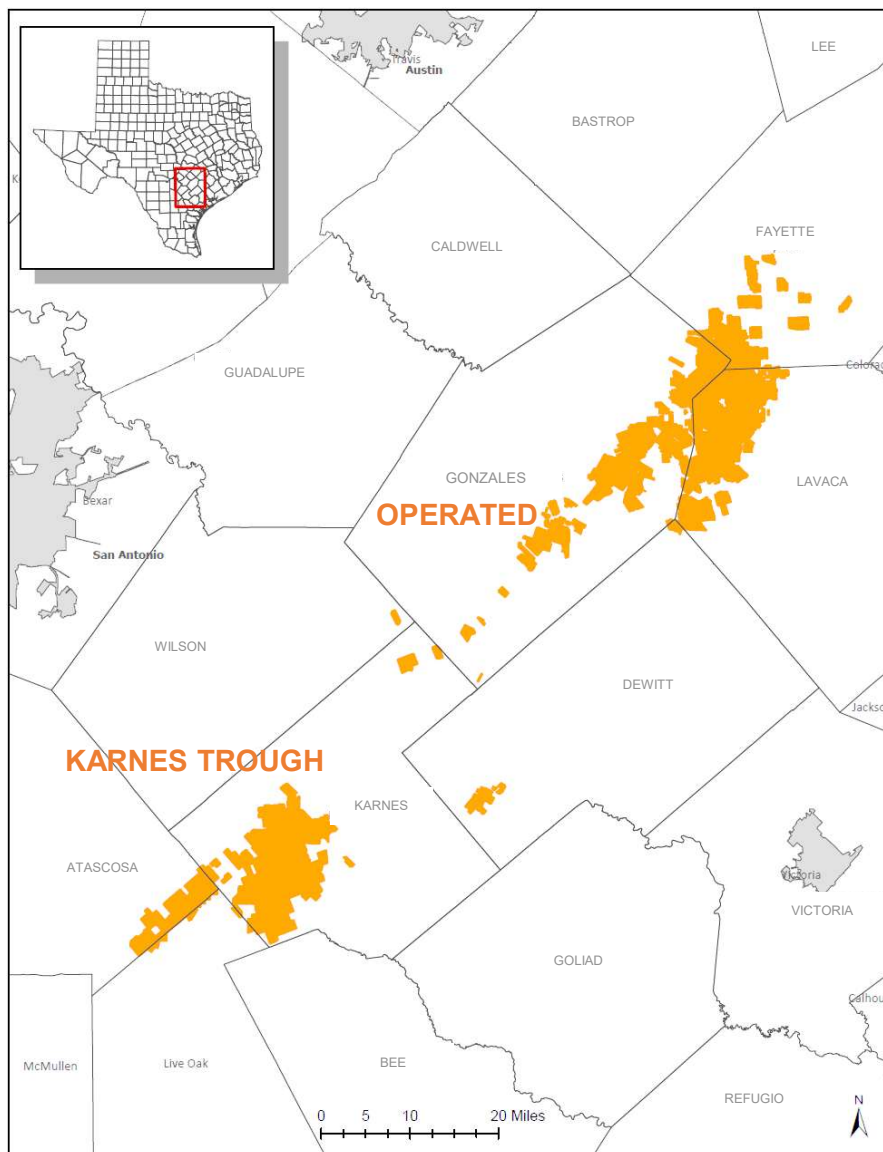
Expect to bring 38 operated wells onstream - **35 Lower Eagle Ford wells and 3 Upper Eagle Ford wells**

Realized ~ **11% improvement in drilling and completion costs per lateral foot** in H1/2025, over 2024

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

**Two successful refracs** extends inventory duration and improves capital efficiencies



# CANADA LIGHT OIL: PEMBINA DUVERNAY / VIKING

## High netback light oil

Pembina Duvernay Shale is a growth asset in the Canadian portfolio

### Pembina Duvernay

#### 140 net sections

Demonstration-stage light oil resource play

Produced **6,665 boe/d** in Q2/2025 (80% liquids)

Expect to bring **9 net wells** onstream in 2025

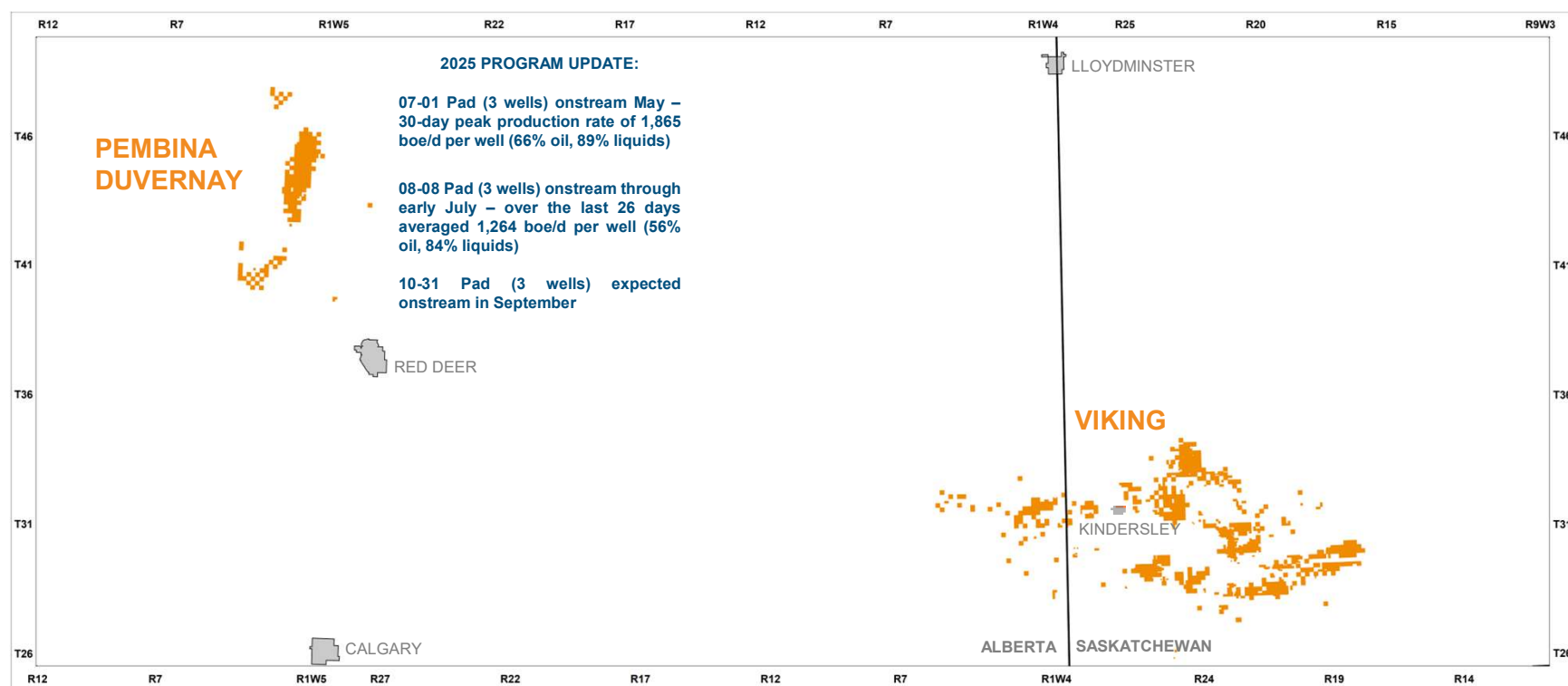
### Viking

#### 355 net sections

Stable production and meaningful asset level free cash flow<sup>(1)</sup>

Produced **9,700 boe/d** in Q2/2025 (81% liquids)

Expect to bring **~ 85 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)

**524 net sections**

Produced **11,000 boe/d** in Q2/2025 (85% oil)

Expect to bring **~ 12 net MLHZ wells** onstream in 2025

### Peavine (Clearwater)

Partnership with Peavine Métis Settlement covering

**134.5 contiguous sections**

Produced **19,700 boe/d** in Q2/2025 (100% oil)

Expect to bring **~ 42 net MLHZ wells** onstream in 2025

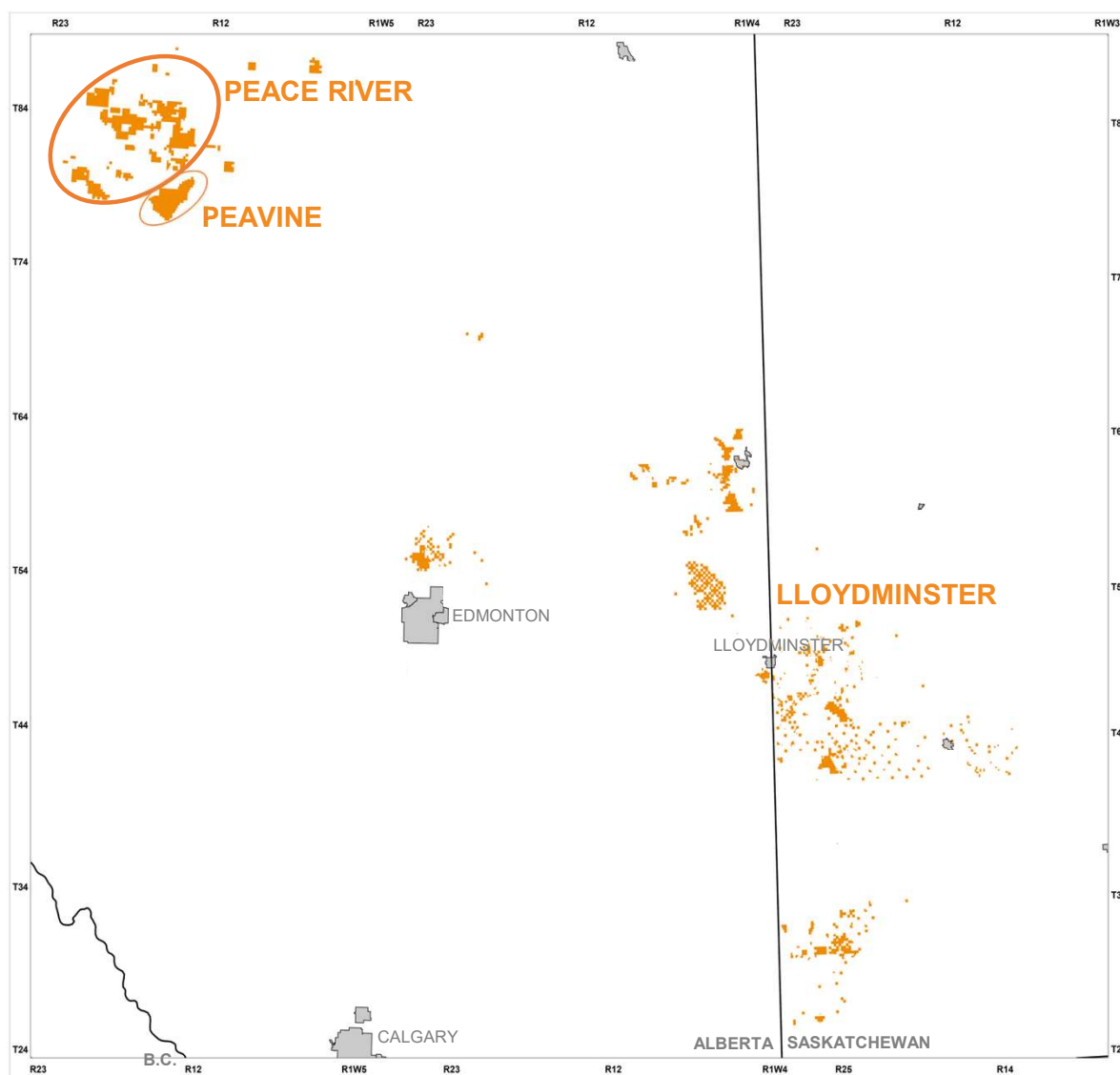
### Lloydminster (Mannville)

**523 net sections**

Produced **12,700 boe/d** in Q2/2025 (98% oil)

Targeting multiple horizons within the Mannville group of formations

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



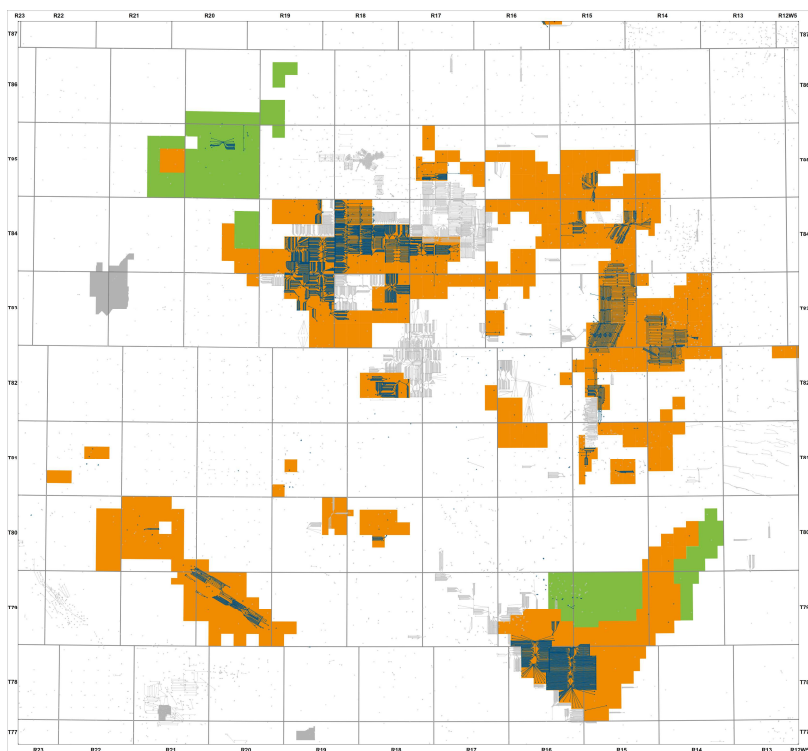
# CANADA HEAVY OIL: LAND EXTENSIONS

## Leveraging heavy oil expertise and recent exploration success

### Peace River (Clearwater + Bluesky)

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

**Acquired 44.5 net sections** on the Peavine Métis Settlement bringing total land position to 134.5 net sections

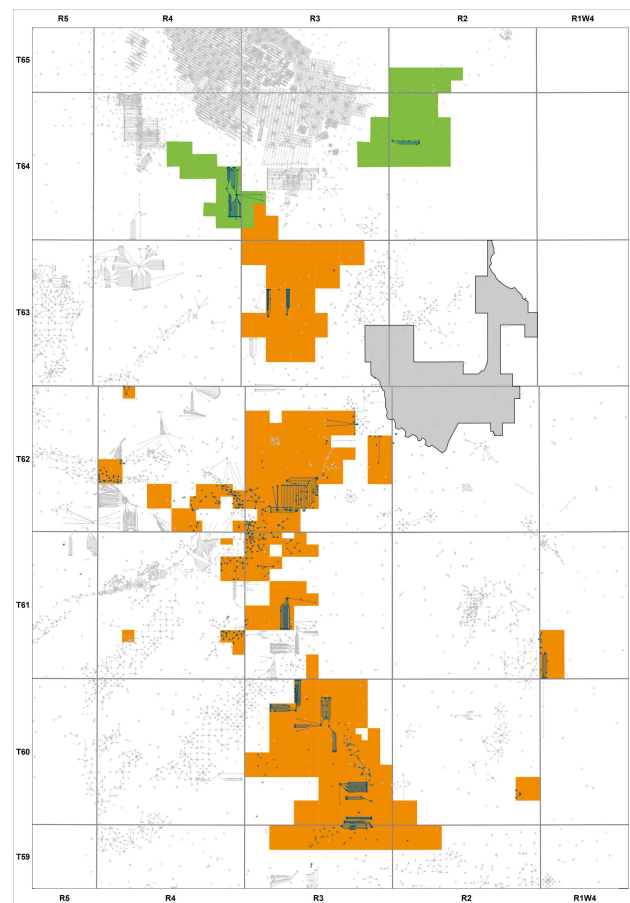


Baytex legacy lands   Recent land agreements

### Lloydminster (Mannville)

**Farm-in agreement on 17.75 sections** near Cold Lake

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



# SUPPLEMENTARY INFORMATION

NYSE | TSX BTE

BAYTEXENERGY.COM

# 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



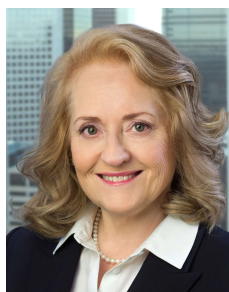
**Tiffany ("T.J.")  
Cepak**



**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<sup>(1)</sup> ALLOCATION POLICY

## Shareholder return framework to prioritize balance sheet

### Total Debt<sup>(2)</sup> Above \$1.5 billion

#### Adjusted Funds Flow<sup>(3)</sup>

Less: Exploration and Development Expenditures

Less: Abandonment and Reclamation / Leasing Expenditures



#### Free Cash Flow

Balance Sheet

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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(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        | Q4 2024        | 2024           | Q1 2025        | Q2 2025        |
|---------------------------------------------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| <b>Benchmark Prices</b>                                       |                |                |                |                |                |                |                |                |                |                |                |                |
| WTI crude oil (US\$/bbl)                                      | \$76.13        | \$73.78        | \$82.26        | \$78.32        | \$77.62        | \$76.96        | \$80.57        | \$75.10        | \$70.27        | \$75.72        | \$71.42        | \$63.74        |
| NYMEX natural gas (US\$/MMbtu)                                | \$3.42         | \$2.10         | \$2.55         | \$2.88         | \$2.74         | \$2.24         | \$1.89         | \$2.16         | \$2.79         | \$2.27         | \$3.65         | \$3.44         |
| <b>Production</b>                                             |                |                |                |                |                |                |                |                |                |                |                |                |
| Crude oil (bbl/d)                                             | 65,869         | 68,143         | 110,967        | 109,693        | 88,849         | 106,596        | 110,734        | 112,602        | 106,888        | 109,207        | 102,527        | 105,067        |
| Natural gas liquids (bbl/d)                                   | 7,213          | 8,620          | 18,004         | 23,160         | 14,304         | 19,299         | 20,167         | 19,836         | 21,208         | 20,129         | 19,046         | 19,948         |
| Natural gas (mcf/d)                                           | 82,066         | 77,989         | 129,780        | 165,121        | 114,010        | 148,353        | 139,764        | 132,175        | 148,792        | 142,262        | 135,731        | 138,482        |
| Oil equivalent (boe/d) <sup>(1)</sup>                         | 86,760         | 89,761         | 150,600        | 160,373        | 122,154        | 150,620        | 154,194        | 154,468        | 152,894        | 153,048        | 144,194        | 148,095        |
| % Liquids                                                     | 84%            | 86%            | 86%            | 83%            | 84%            | 84%            | 84%            | 86%            | 84%            | 85%            | 84%            | 84%            |
| <b>Adjusted Funds Flow (\$/boe)</b>                           |                |                |                |                |                |                |                |                |                |                |                |                |
| Total sales, net of blending and other expense <sup>(2)</sup> | \$63.48        | \$66.82        | \$80.34        | \$68.00        | \$70.82        | \$67.12        | \$75.93        | \$71.97        | \$66.60        | \$70.43        | \$71.38        | \$61.16        |
| Royalties <sup>(3)</sup>                                      | (11.94)        | (13.21)        | (17.33)        | (15.49)        | (15.02)        | (15.26)        | (17.14)        | (15.75)        | (14.69)        | (15.71)        | (16.02)        | (13.16)        |
| Operating expense <sup>(3)</sup>                              | (14.40)        | (14.62)        | (12.57)        | (11.17)        | (12.80)        | (12.65)        | (11.95)        | (11.76)        | (10.36)        | (11.67)        | (11.38)        | (11.95)        |
| Transportation expense <sup>(3)</sup>                         | (2.18)         | (1.78)         | (2.02)         | (2.02)         | (2.00)         | (2.18)         | (2.37)         | (2.60)         | (2.35)         | (2.38)         | (2.35)         | (2.44)         |
| Operating Netback <sup>(2)</sup>                              | \$34.96        | \$37.21        | \$48.42        | \$39.32        | \$41.00        | \$37.03        | \$44.47        | \$41.86        | \$39.20        | \$40.67        | \$41.63        | \$33.61        |
| General and administrative <sup>(3)</sup>                     | (1.50)         | (1.87)         | (1.48)         | (1.51)         | (1.57)         | (1.64)         | (1.50)         | (1.26)         | (1.45)         | (1.46)         | (1.97)         | (1.65)         |
| Cash interest <sup>(3)</sup>                                  | (2.35)         | (3.46)         | (4.08)         | (3.84)         | (3.58)         | (3.89)         | (3.84)         | (3.53)         | (3.47)         | (3.68)         | (3.61)         | (3.33)         |
| Realized financial derivative (loss) gain <sup>(3)</sup>      | (0.69)         | 2.00           | 0.15           | 0.84           | 0.81           | 0.40           | (0.16)         | 0.02           | (0.15)         | 0.03           | (0.01)         | (0.88)         |
| Other <sup>(4)</sup>                                          | (1.45)         | (0.39)         | (1.03)         | (0.77)         | (0.90)         | (0.98)         | (1.00)         | 0.76           | (1.29)         | (0.63)         | (0.30)         | (0.52)         |
| <b>Adjusted funds flow <sup>(5)</sup></b>                     | <b>\$30.35</b> | <b>\$33.49</b> | <b>\$41.98</b> | <b>\$34.03</b> | <b>\$35.76</b> | <b>\$30.92</b> | <b>\$37.97</b> | <b>\$37.85</b> | <b>\$32.84</b> | <b>\$34.93</b> | <b>\$35.74</b> | <b>\$27.23</b> |

- (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 expense, transportation expense, general and administrative expense, cash interest expense or realized financial derivative gain or 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 divided by barrels of oil equivalent production volume for the applicable period. Refer to the Q2 2025 MD&A available on the SEDAR+ website at [www.sedarplus.ca](http://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) <sup>(1)</sup> | ~ \$1.2                       |
| Production (boe/d) <sup>(1)</sup>                                     | ~ 148,000                     |
| Expenses:                                                             |                               |
| Average royalty rate (%) <sup>(2)</sup>                               | ~ 22%                         |
| Operating (\$/boe) <sup>(3)</sup>                                     | \$11.75 - \$12.50             |
| Transportation (\$/boe) <sup>(3)</sup>                                | \$2.40 - \$2.55               |
| General and administrative (\$ millions) <sup>(3)</sup>               | \$95 (\$1.76/boe)             |
| Cash interest (\$ millions) <sup>(3)</sup>                            | \$180 (\$3.33/boe)            |
| Current Income Taxes (\$ millions)                                    | ~ 1% of EBITDA <sup>(4)</sup> |
| Leasing expenditures (\$ millions)                                    | \$15                          |
| Asset retirement obligations (\$ millions)                            | \$20                          |

(1) 2025 production guidance range: 148,000 to 152,000 boe/d. E&D expenditures range \$1.2 to \$1.3B.

(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 operating expense, transportation expense, general and administrative expense or cash interest expense divided by barrels of oil equivalent production volume for the applicable period.

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



## 2025 ADJUSTED FUNDS FLOW SENSITIVITIES

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| Sensitivities                                     | Estimated Effect on Annual Adjusted Funds Flow <sup>(1)(2)</sup> (\$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) Adjusted funds flow sensitivities are prior to the impact of the commodity hedging program.



# FORWARD LOOKING STATEMENTS ADVISORY

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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 and that we are trending to the low end of guidance for exploration and development expenditures and production; expectations for 2025 free cash flow at prices of US\$60 WTI, US\$65 WTI and US\$70 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 and puts to ensure a modest return on our highest breakeven assets and the percentage of our expected production that is hedged until the end of Q1/2026; 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 (including as a result of tariffs); 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.

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, 2024, 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 June 30, 2025, cash flows from operating activities was \$354 million and free cash flow was \$3 million. For the six months ended June 30, 2025, cash flows from operating activities was \$786 million and free cash flow was \$56 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 six months ended June 30, 2025, which is incorporated herein by reference, and available on the SEDAR+ website at [www.sedarplus.ca](http://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 June 30, 2025, petroleum and natural gas sales were \$887 million and operating netback was \$453 million. For the six months ended June 30, 2025, petroleum and natural gas sales were \$1.9 billion and operating netback was \$993 million. 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 six months ended June 30, 2025, which is incorporated herein by reference, and available on the SEDAR+ website at [www.sedarplus.ca](http://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 June 30, 2025, petroleum and natural gas sales were \$887 million and total sales, net of blending and other expense were \$824 million. For the six months ended June 30, 2025, petroleum and natural gas sales were \$1.9 billion and total sales, net of blending and other expense were \$1.8 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 six months ended June 30, 2025, which is incorporated herein by reference, and available on the SEDAR+ website at [www.sedarplus.ca](http://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 six months ended June 30, 2025 and 2024 is calculated below.

|                                                        | Three Months Ended June 30 |           | Six Months Ended June 30 |            |
|--------------------------------------------------------|----------------------------|-----------|--------------------------|------------|
| (\$ thousands)                                         | 2025                       | 2024      | 2025                     | 2024       |
| Dividends declared                                     | \$ 17,304                  | \$ 18,161 | \$ 34,593                | \$ 36,655  |
| Consideration paid for the repurchase of common shares | 4,056                      | 79,268    | 16,809                   | 82,273     |
| Return of Capital                                      | \$ 21,360                  | \$ 97,429 | \$ 51,402                | \$ 118,928 |

## 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

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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 June 30, 2025, credit facilities were \$317 million and net debt was \$2.3 billion. For the three months ended June 30, 2025, cash flows from operating activities were \$354 million and adjusted funds flow was \$367 million. For the six months ended June 30, 2025, cash flows from operating activities were \$786 million and adjusted funds flow was \$831 million.

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 six months ended June 30, 2025, which is incorporated herein by reference, and available on the SEDAR+ website at [www.sedarplus.ca](http://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 2024 is included in our Annual Information Form for the year ended December 31, 2024 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 331 proved and 140 probable locations as at December 31, 2024 and 294 unbooked locations. In the Duvernay, Baytex's net drilling locations include 42 proved and 20 probable locations as at December 31, 2024 and 153 unbooked locations. In the Viking, Baytex's net drilling locations include 541 proved and 168 probable locations as at December 31, 2024 and 261 unbooked locations. In the heavy oil business unit, Baytex's net drilling locations include 149 proved and 112 probable locations as at December 31, 2024 and 663 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.

# NOTES

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