A Premier Canadian Energy Company

TECHNICAL LEADERSHIP. FOCUSED GROWTH.
COMPELLING RETURNS.

May 2026

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. 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 May 7, 2026 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. 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 March 31, 2026.

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

BAYTEX OVERVIEW

Focused Canadian Oil Producer

Technical leadership and disciplined capital allocation

Commitment to Shareholder Returns

Industry-leading net cash position with flexibility to invest, grow, and return capital through the cycle

Compelling Valuation

Accelerating growth and shareholder returns support meaningful re-rate potential

Corporate Profile	
Shares Outstanding (1)	723 million
Market Capitalization (2)	$4.9 billion
Net (cash) debt (3)	($0.6 billion)
Quarterly dividend (4)	$0.0225 per share
Dividend yield (5)	1.3%
Annual Production (6)	69 – 71 Mboe/d
% Oil and NGL (6)	89%

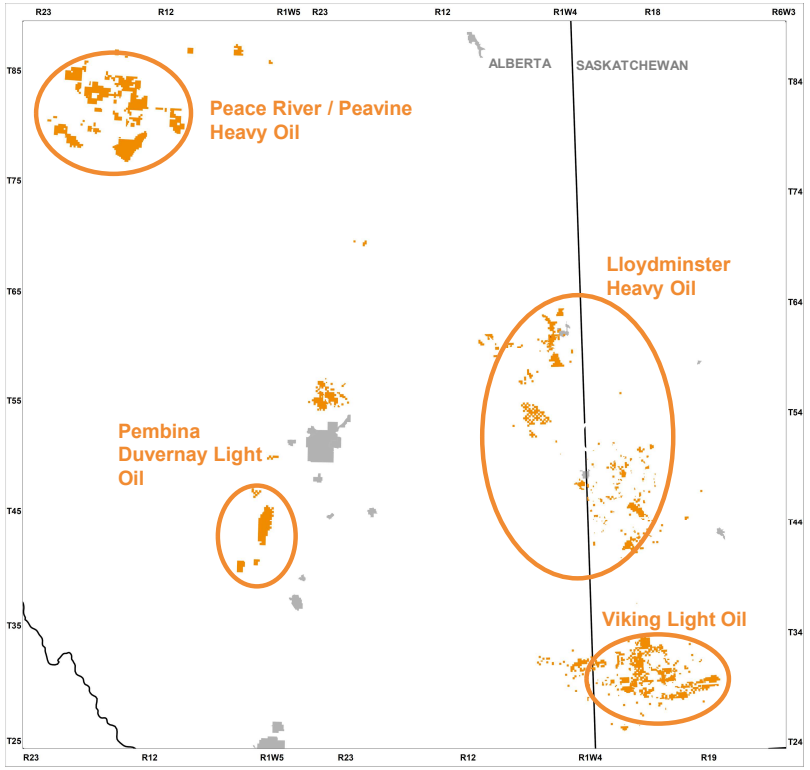
1) Shares outstanding as at May 6, 2026.
2) Market capitalization based on closing share price on the Toronto Stock Exchange on May 6, 2026.
3) Net (cash) debt as at March 31, 2026. Net (cash) debt is a capital management measure. Refer to the Capital Management Measures Advisory section in this presentation 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 represents 2026 guidance.

STRATEGIC PRIORITIES

Committed to technical leadership and long-term value creation

1. **Target 15% annual total shareholder return**
   - Production growth, dividends and share buybacks – at a mid-cycle WTI price of US$70/bbl
   - Underpinned by a strong, flexible balance sheet
2. **Building a culture of disciplined growth and long-term value**
   - Deliver 6% to 8% annual production growth
   - Continuous improvement in cash costs and capital efficiencies; target a long-term sustaining break-even price of under US$50/bbl WTI
3. **Achieve full scale development in the Duvernay and advance heavy oil opportunity set**
   - Duvernay: targeting 20,000 - 25,000 boe/d by 2029-2030, supported by 91,500 net acres and ~ 210 drilling locations
   - Heavy oil exploration: increase activity to expand development inventory and test new play concepts across heavy oil fairway - Utikuma seismic survey and step out wells
   - Peavine waterflood pilots: potential for enhanced recovery and moderated decline rates; first injection June 2026
   - Gemini thermal SAGD: 44 million barrels probable reserves; technical planning advancing toward potential FID in 2027

Premier Canadian Assets



CAPITAL ALLOCATION PRIORITIES

Capital Allocation Principles

Maximize asset value through disciplined investment

- Maintenance capital to sustain production
- Invest in long-term infrastructure to support organic growth
- Pursue targeted exploration and strategic tuck-in acquisitions to expand inventory and future opportunity

Provide meaningful shareholder returns

2026 Prioritizes Meaningful Shareholder Returns

Net cash position

Significant portion to be returned to shareholders

Share buybacks prioritized:

- Purchases under NCIB commenced December 24, 2025
- Share count reduced by 5.9% through May 6, 2026
- Current NCIB (expires July 1, 2026) authorizes up to 66.2 million shares
- Intend to renew NCIB capacity for repurchases in H2/2026

Dividend maintained at $0.09 per share (annualized)

DISCIPLINED 2026 CAPITAL BUDGET

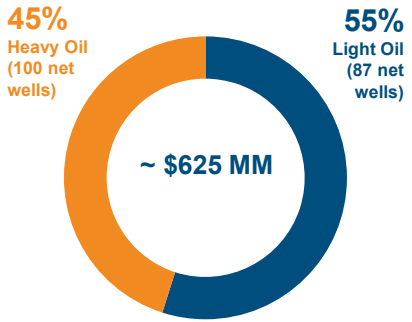
Increased production guidance driven by strong operating performance and planned 2H activity

~ 7% annual production growth

Significant value creation in the Pembina Duvernay

Consistent heavy oil performance delivers reliable returns

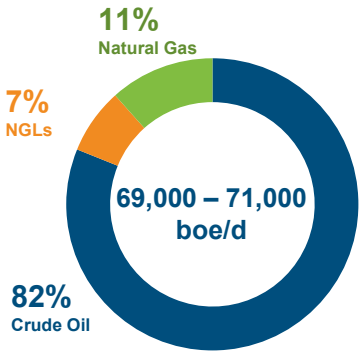
2026e Capital Expenditure



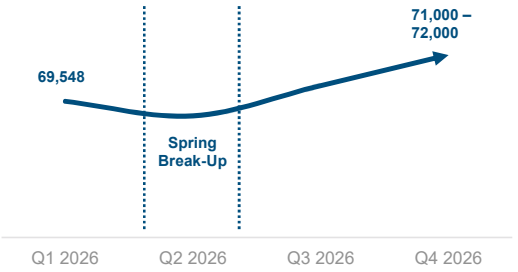
Capex Breakdown ($MM)

Maintenance	435
Growth	90
Long-term Infrastructure	50
Exploration and Land	50
Total	**625**

2026e Production



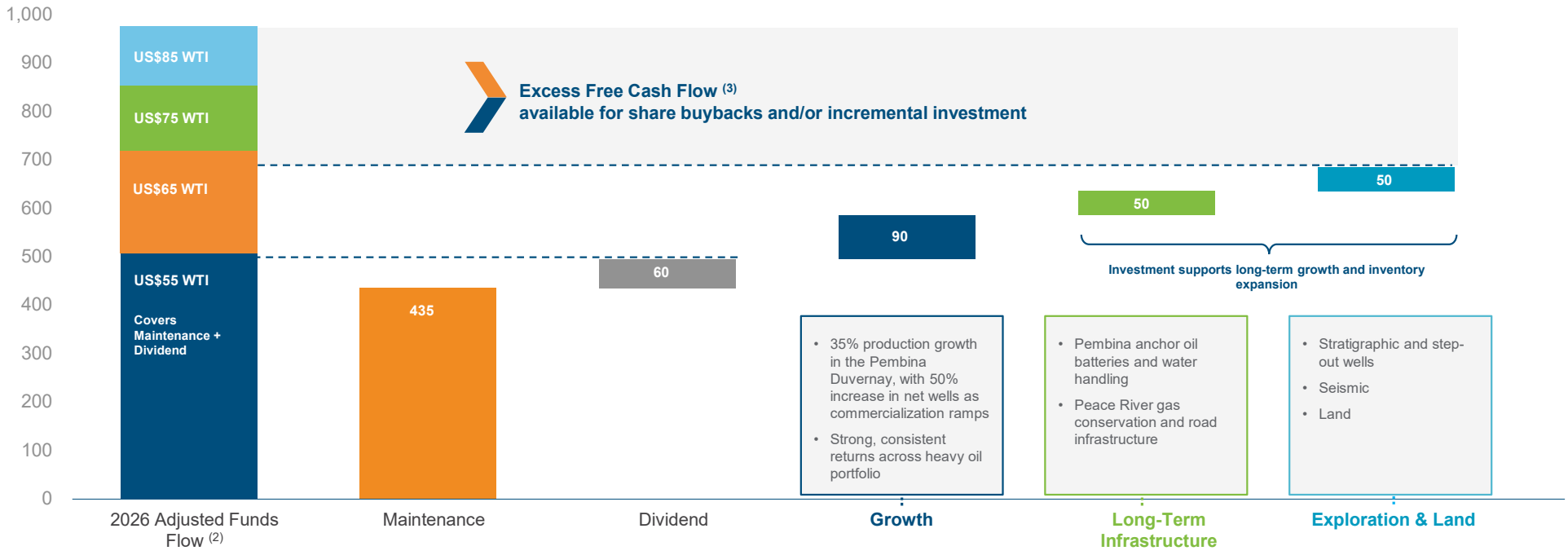
Production Profile (boe/d)



2026 CAPITAL ALLOCATION WATERFALL

Enabling growth, returns, and value creation

Capital Allocation ($MM)

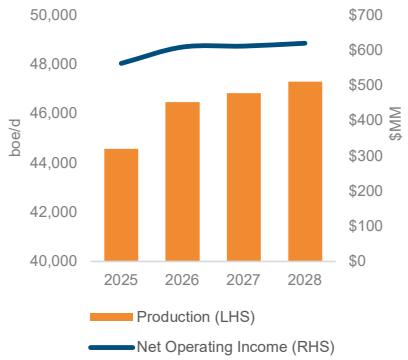


1) Commodity price assumptions: WTI-WCS Differential – US$12.50/bbl, AECO Gas - $3.00/Mcf; Exchange rate (CAD/USD) = 1.4. Adjusted funds flow sensitivities includes the impact of ARO and leasing expenditures.
2) Capital management measure. Refer to the Specified Financial Measures Advisory section in this presentation for further information.
3) Excess free cash flow is calculated as free cash flow less dividend payments. Free cash flow is a 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.

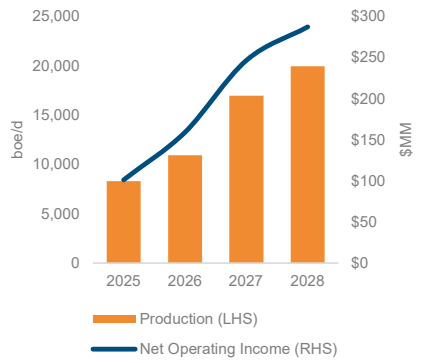
3-YEAR OUTLOOK

Sustainable value creation

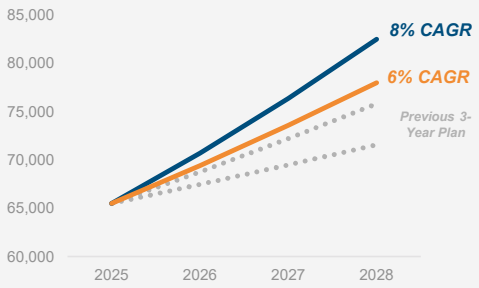
Heavy Oil 3-Year Outlook



Pembina Duvernay 3-Year Outlook



Production Profile (boe/d)



Heavy Oil: Modest growth while generating substantial free cash flow

Pembina Duvernay: > 30% production CAGR(2) over three years drives 80% increase in net operating income

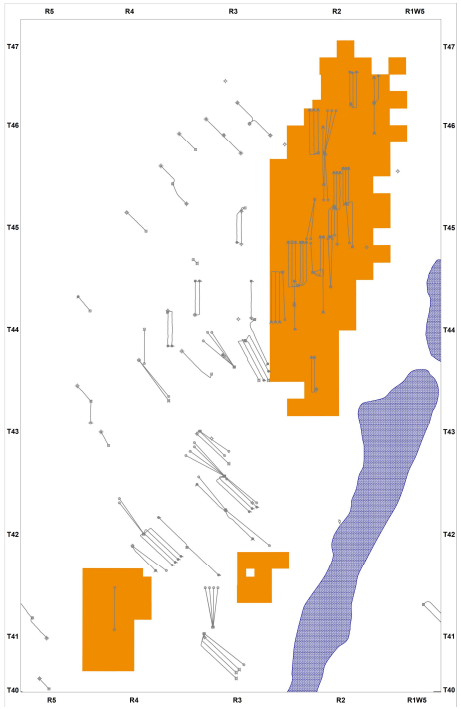
6-8% Production CAGR(2): accelerating growth in a more constructive pricing environment

Balance Sheet: Net cash(3) position maintained during plan period
Shareholder Returns: Excess free cash flow available for share buybacks, dividends or incremental investment

1) Commodity price assumptions: WTI – US$70/bbl, WTI-WCS Differential – US$12.50/bbl, AECO Gas - $3.00/Mcf; Exchange rate (CAD/USD) = 1.38.
2) CAGR refers to the compound annual growth rate, representing the average yearly growth in production over a set period.
3) Cash less principal amount of Senior Notes outstanding.

PEMBINA DUVERNAY – SIGNIFICANT VALUE CREATION OPPORTUNITY

Creating long-term value through scalable light oil growth



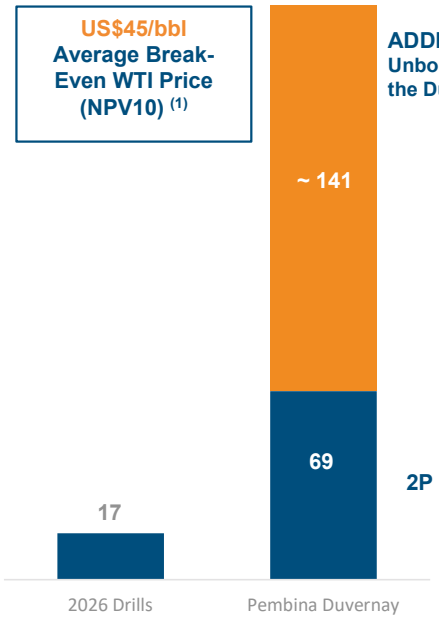
91,500 net acres

Highly concentrated core Duvernay position

~ 210 locations

Supports growth to 20,000 - 25,000 boe/d

US$45/bbl
Average Break-Even WTI Price (NPV10) (1)



ADDITIONAL INVENTORY
Unbooked locations targeting the Duvernay formation

2P BOOKED

Strong 2025 performance

Record well results

Transitioning to 1-rig program

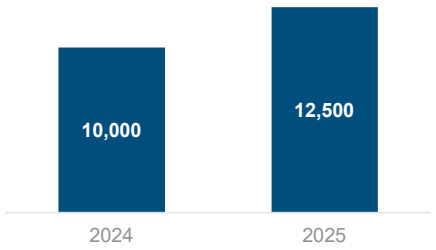
13 wells onstream in 2026; ~18 wells per year thereafter

1) Break-even WTI price is the minimum price required to cover all costs associated with drilling and operating a well discounting the future cash flow stream at a 10% discount rate.

EXECUTION AND PERFORMANCE IN THE PEMBINA DUVERNAY

Transition to commercialization with improved well economics

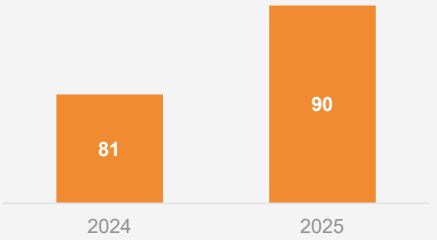
25% Increase in Completed Lateral Length (CLL, feet)



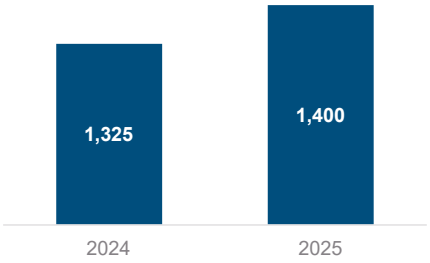
Execution Improvements

- Enhanced drilling assembly
- Improved completion uniformity
- Tapered cluster design
- Optimized pumping schedule

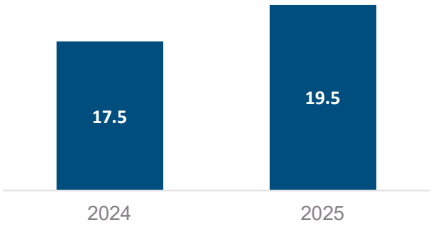
11% Improvement in EUR [1] (Boe per foot, CLL)



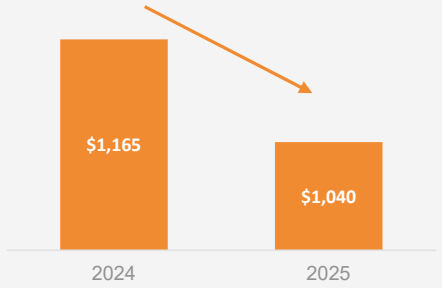
5% Improvement in Drilling Efficiency (ft/day)



10% Improvement in Completion Efficiency (Pumping hours/day)



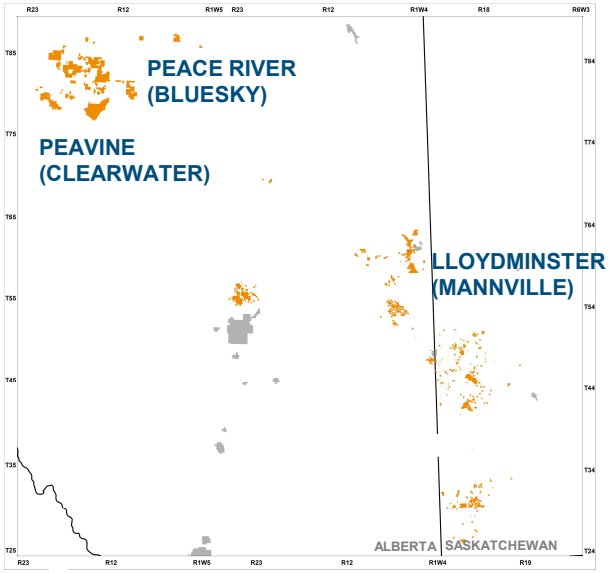
11% Improvement in Well Cost (DCET, $/foot CLL)



1) EUR refers to the estimated ultimate recovery of a well, an approximation of the quantity of oil or gas that is expected to be economically recoverable over its producing life.

HEAVY OIL – STABLE, PROFITABLE CASH GENERATION

Demonstrated success drives reliable returns



750,000 net acres

Significant land holdings across the heavy oil fairway

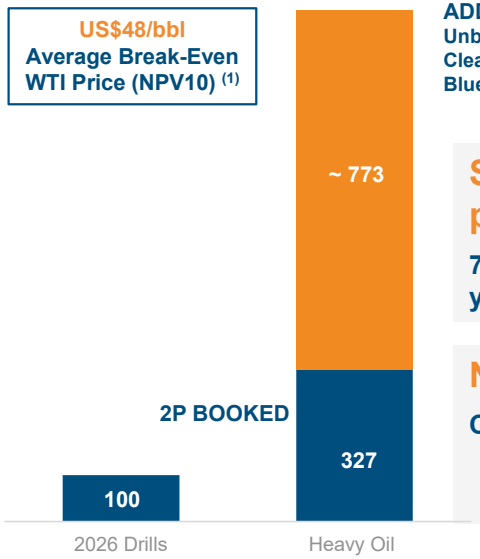
~ 1,100 locations

Innovative MLHZ and circulation HZ development

Enhanced recovery

~ 10% of production on water and polymer floods

Heavy Oil Inventory



ADDITIONAL INVENTORY
Unbooked locations targeting the Clearwater, Mannville Group and Bluesky formations

Strong 2025 performance

7% organic growth year-over-year (2)

New pool discoveries

Consistent track record

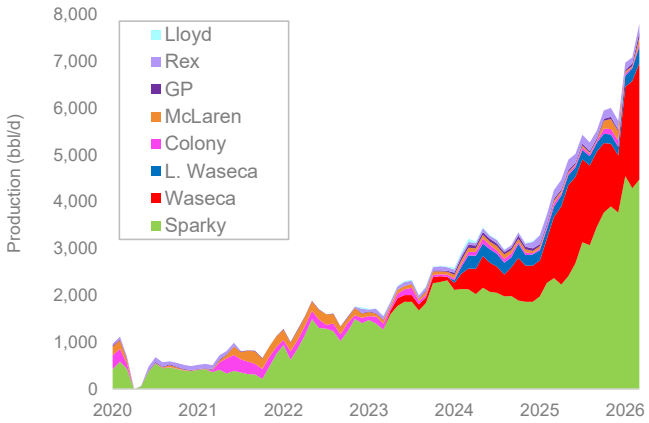
1) Break-even WTI price is the minimum price required to cover all costs associated with drilling and operating a well discounting the future cash flow stream at a 10% discount rate. Pricing assumption: WTI-WCS differential = US$12.50/bbl.

2) Excludes non-core divestitures.

NORTHEAST MANNVILLE: SIGNIFICANT STACKED RESOURCE, DEMONSTRATED GROWTH

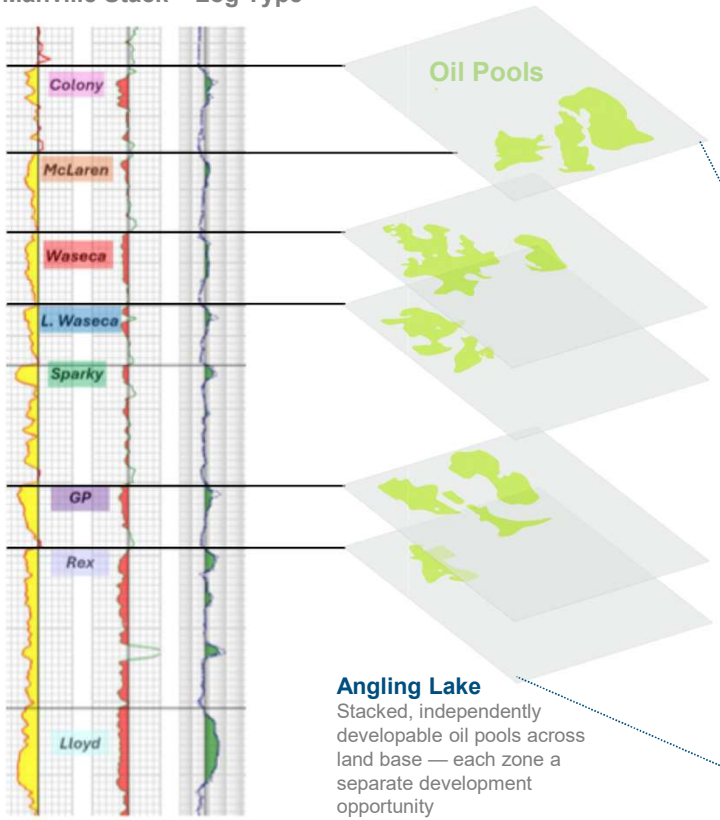
Eight discrete development horizons across >100 sections – delineation continues to expand drilling inventory

NE Alberta Production Growth by Horizon



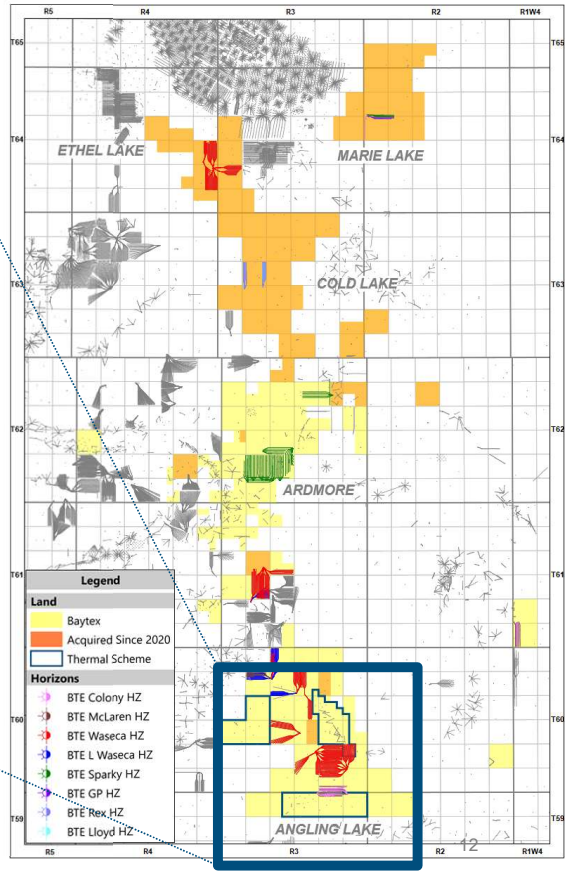
- Five years of consistent production growth driven by strong well economics and capital efficiencies
- Active 2026 program of ~46 wells, with further delineation, stratigraphic tests and new trials across multiple zones

Manville Stack – Log Type



Angling Lake
Stacked, independently developable oil pools across land base — each zone a separate development opportunity

NE Alberta Land Position

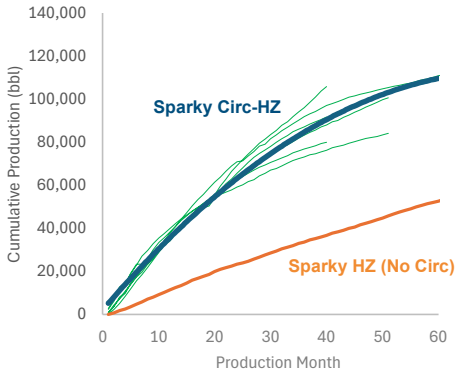


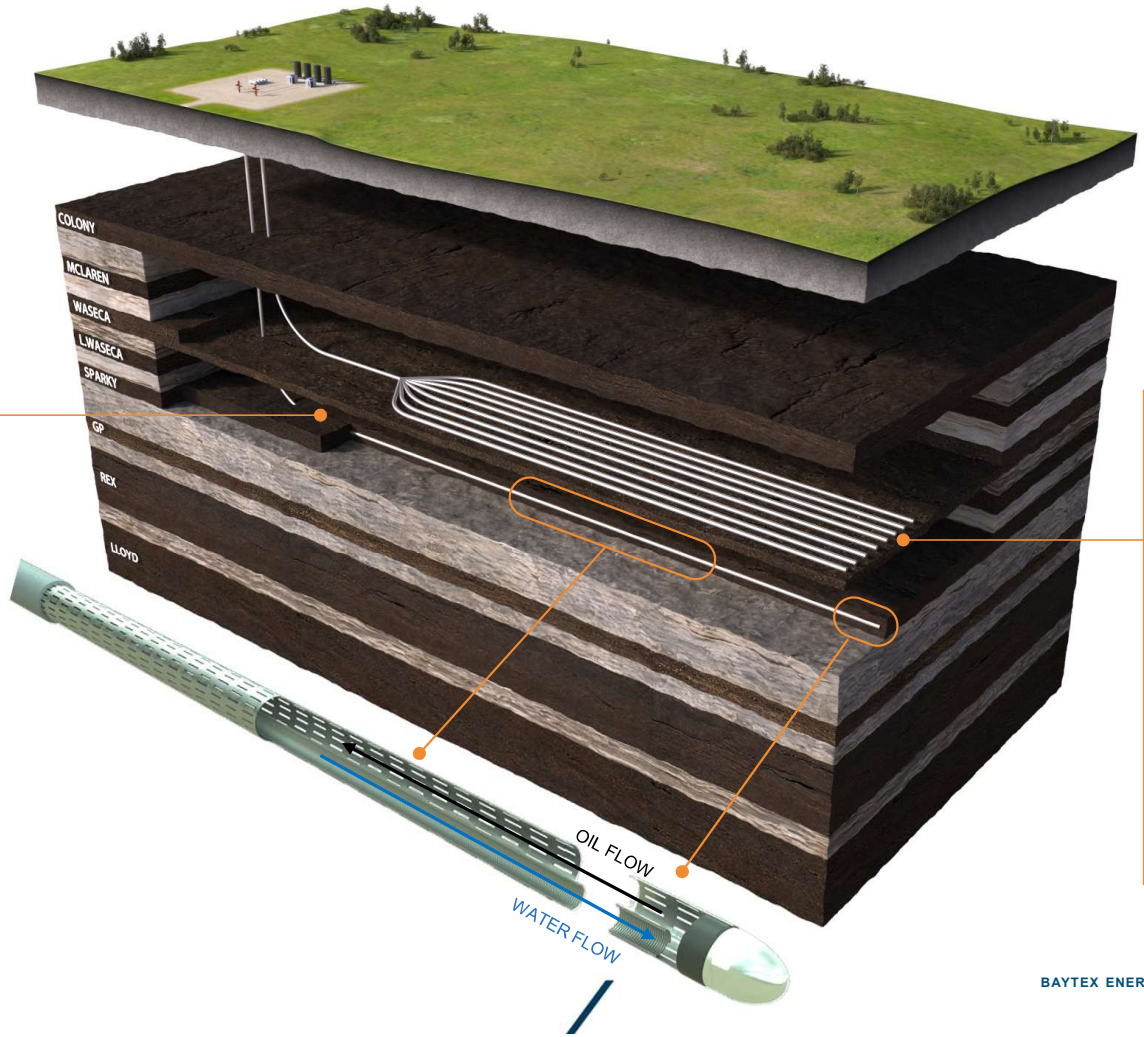
FIT-FOR-PURPOSE WELL DESIGN: PROVEN, LOW-COST, AND REPEATABLE AT SCALE

Circulation String Horizontal

- Utilized at Lloydminster to target unconsolidated reservoirs
- Horizontal well with a slotted liner and circulation string allows oil and sand to flow to surface
- Up to 16 wells per section

Baytex Sparky Well Performance – South Ardmore





Multi-Lateral Horizontal

- Utilized at Lloydminster (Mannville), Peavine (Clearwater) and Peace River (Bluesky) to target consolidated reservoirs
- 4-12 open-hole lateral legs from a single wellbore
- 4-5 wells per section

INCREASING HEAVY OIL EXPLORATION ACTIVITY

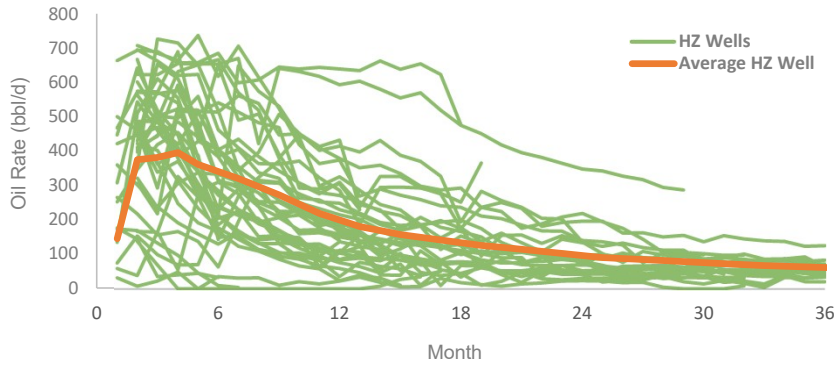
Building on our heavy oil expertise and enhancing prospect inventory

Targeting Pekisko mounds (pinnacle reef-like buildups) near our Peace River / Peavine operations

Acquired additional 40 sections at Utikuma in Q1 2026, bringing total land holdings to 109 sections

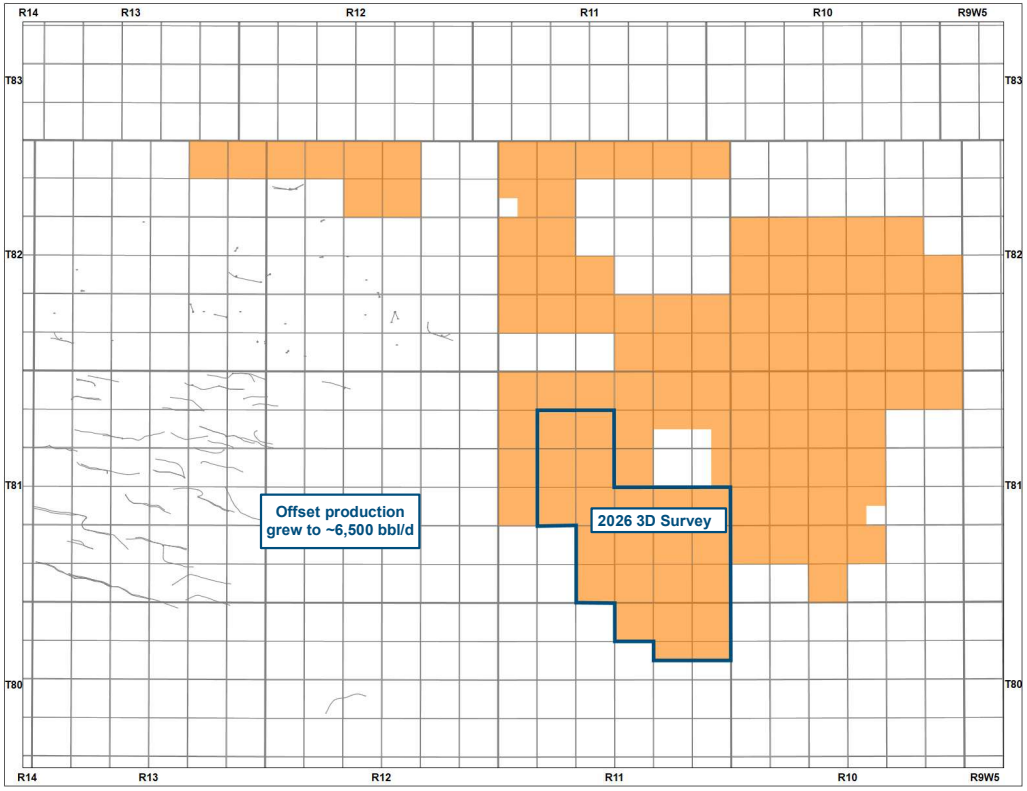
Completed 21-square mile seismic survey, and following interpretation, first exploration well could be drilled in Q1 2027

Offsetting Pekisko Mound Production



Source: GeoSCOUT

Utikuma Land Position



PEAVINE WATERFLOOD PILOTS

Evaluating incremental resource recovery and production duration via waterflood

Waterflood success has been demonstrated across the Clearwater

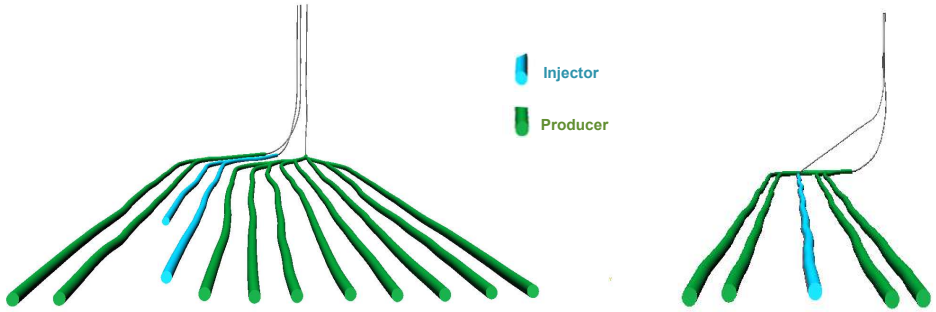
Initiating 2 pilots at Peavine in Q2/Q3 2026 to evaluate:

- **Reservoir repressuring:** low-cost producer to injector conversions (5-33 Pad)
- **Pressure maintenance:** dedicated injection within new development (14-36 Pad)

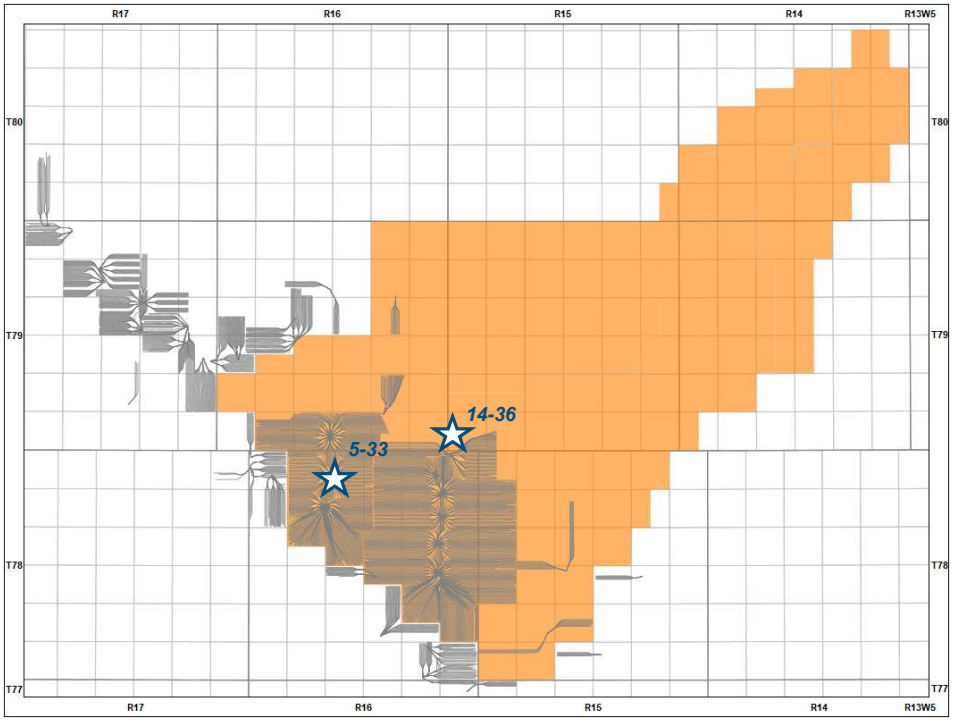
Gaining insight into enhanced recovery potential on both developed and undeveloped acreage

5-33 Pad
Low-Cost Multi-lateral Injection Conversion

14-36 Pad
Tuning Fork Multi-lateral with Injector in Gap



Peavine Land Position



Combining the capital efficiency of multi-lateral development with the potential for enhanced recovery and moderated declines

GEMINI SAGD PROJECT REPRESENTS SIGNIFICANT SOURCE OF LONG-TERM VALUE

Advancing planning toward potential final investment decision in 2027

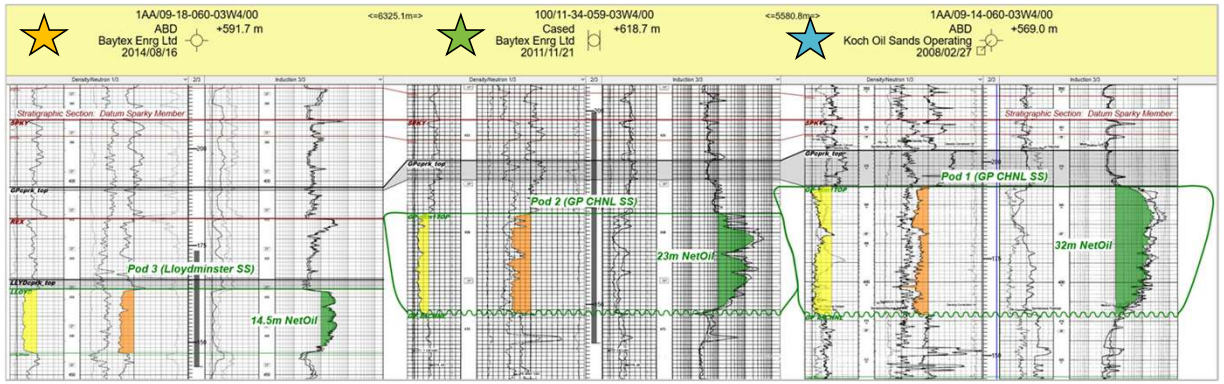
Located in the heart of our northeast Alberta Mannville Stack development

~300 million barrels of exploitable oil in place (>10 meters pay thickness)

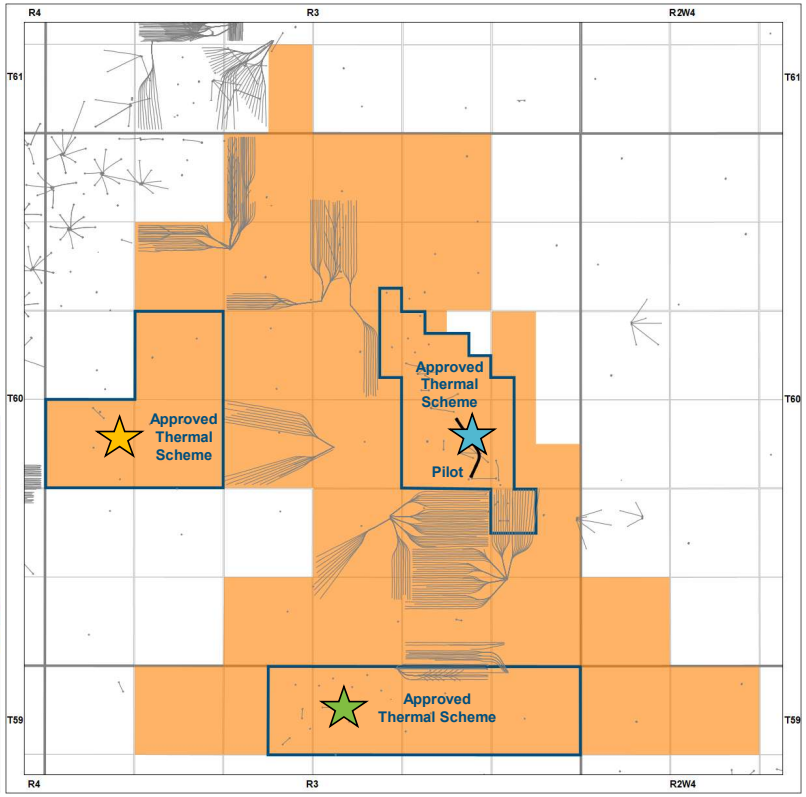
44 million barrels of booked probable reserves at year-end 2025

Proven productivity from successful pilot

Approved 5,000 bbl/d SAGD development scheme supports first phase of development



Gemini Land Position



STRONG WELL ECONOMICS[1] ACROSS PORTFOLIO

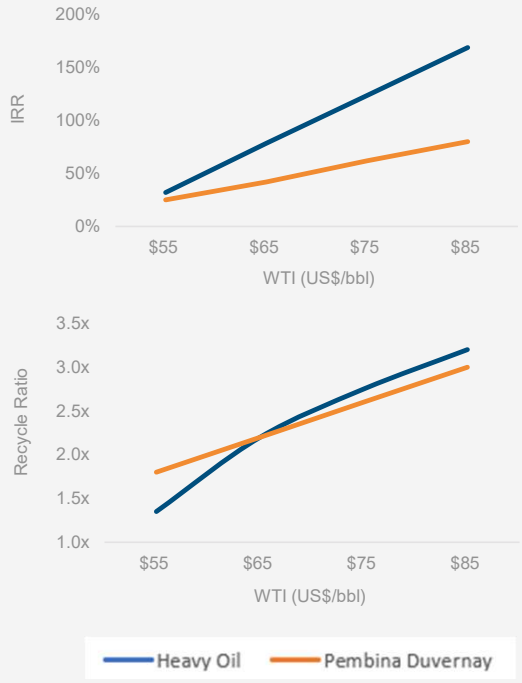
Heavy Oil [2]

DCET ($MM) [4]	**$2.0 - $3.0**	
EUR (Mboe) [5]	**100 - 175** *(89% - 100% liquids)*	
IP 365 (boe/d)	**100 - 145** *(86% - 100% liquids)*	
WTI	**US$65**	**US$75**
IRRs [6]	**62% - 95%**	**104% - 141%**
Payouts [7]	**13 - 23 months**	**11 - 14 months**
Recycle Ratio [8]	**2.1x - 2.3x**	**2.6x - 2.9x**

Pembina Duvernay [3]

DCET ($MM) [4]	**$12.5**	
EUR (Mboe) [5]	**900 - 1,000** *(76% liquids)*	
IP 365 (boe/d)	**550 - 650** *(84% liquids)*	
WTI	**US$65**	**US$75**
IRR [6]	**42%**	**62%**
Payout [7]	**25 months**	**19 months**
Recycle Ratio [8]	**2.2x**	**2.6x**

Significant Torque to Higher Oil Prices



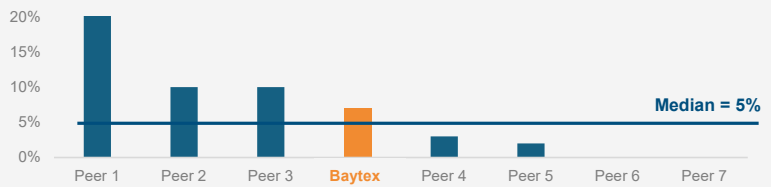
1) Pricing Assumptions: WTI-WCS differential – US$12.50/bbl, AECO Gas – $2.75/Mcf, Exchange Rate (CAD/USD) = 1.4.
2) Heavy oil includes multi-lateral horizontal (MLHZ) and circulation string horizontal wells across the Clearwater, Bluesky and Mannville group.
3) Pembina Duvernay based on an average 4,000 meter completed lateral length (CLL) and 320 meter inter-well spacing.
4) DCET refers to the cost to drill, complete, equip and tie-in a well.
5) EUR refers to the estimated ultimate recovery of a well, an approximation of the quantity of oil or gas that is expected to be economically recoverable over its producing life.
6) IRR refers to the internal rate of return; a measure used to compare the profitability of an investment and represents the discount rate at which the net present value of costs equals the net present value of the benefits. The higher a project's IRR, the more desirable the project.
7) Payout refers to the point at which all costs of drilling and operating a well are recouped from the sale of its production.
8) Recycle ratio is calculated by dividing operating netback on a per boe basis by F&D costs. F&D costs refer to the DCET cost divided by the EUR.

COMPELLING VALUATION UPSIDE

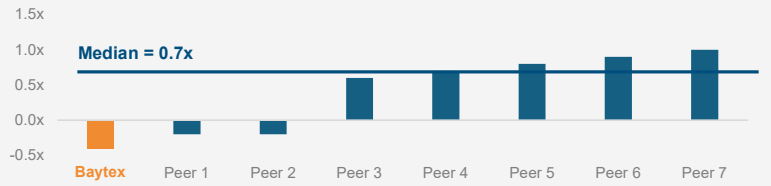
Potential for equity re-rate with competitive growth and balance sheet

- Competitive production growth
- Industry-leading balance sheet
- Compelling valuation

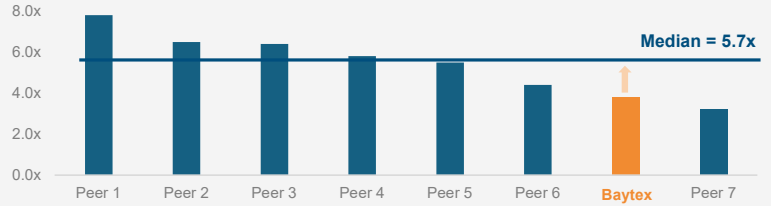
Production Growth (2026/2025) (1)



Net Debt to Adjusted Funds Flow Ratio (2026E) (1)



EV/DACF Multiple (2026E) (1)



1) Source: Peter's & Co., May 4, 2026. Commodity prices: WTI – US$88.55/bbl, WCS differential – US$14.87/bbl; NYMEX Gas - US$3.27/MMbtu; Exchange Rate (CAD/USD) – 1.36.
Peer group includes Athabasca, Headwater, Spartan Delta, Strathcona, Tamarack Valley, Vermilion, Whitecap.

WHY BAYTEX

High-Return Canadian Asset Base Growing 6-8% Annually
10+ years of development inventory across heavy oil and Pembina Duvernay – capital efficient and scalable

15% Annual Total Shareholder Return Target
Delivered through production growth, dividends and share buybacks

Industry-Leading Net Cash Position
Financial flexibility to invest, grow, and return capital through the cycle

Compelling Valuation
Trading at a discount to Canadian peers with accelerating growth and shareholders returns

SUPPLEMENTARY

INFORMATION

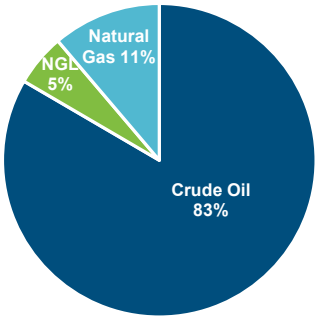
BAYTEXENERGY.COM

NYSE | TSX BTE

STRONG OPERATING LEVERAGE TO CRUDE OIL

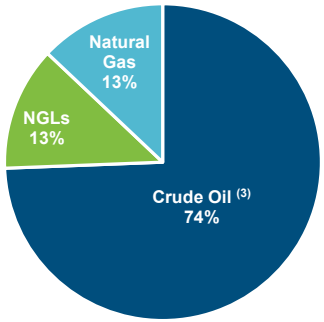
88% production weighting to crude oil; significant drilling inventory

Canada 2025 Production – 65,500 boe/d

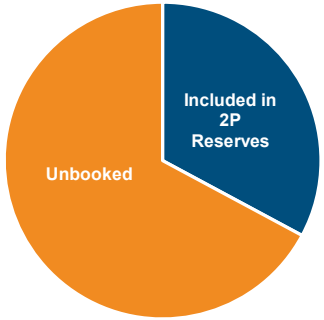


~ 1,100 Total Heavy Oil Drilling Locations

Canada 2P Reserves (YE 2025) - 282 MMboe (1)(2)



~ 210 Total Pembina Duvernay Drilling Locations



1) Baytex's reserves evaluated by McDaniel & Associates, an independent qualified reserves evaluator.
2) Canada proved reserves (1P) at YE 2025: 151 MMboe (crude oil – 67%, NGLs – 17%, natural gas – 16%).
3) Includes 44.5 million barrels of probable reserves associated with the Gemini Thermal project.

2025 RESERVES HIGHLIGHTS - CANADA

Solid reserves growth

Invested $548 million in capital efficient program

Significant contributions from Pembina Duvernay and heavy oil

Demonstrates long-term resiliency and sustainability

Continues strong track record of value creation in Canada

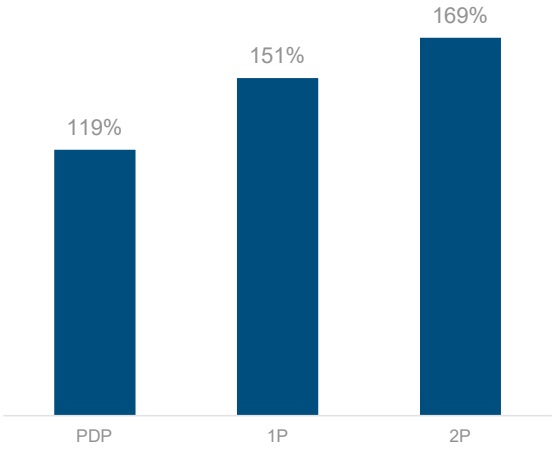
Reserves Category (1)	YE 2025 (MMboe)	YE 2024 (MMboe)	% Change	Production Replacement (2)	F&D Costs (3) ($/boe)	Recycle Ratio (4)
PDP	69	61	+12%	133%	17.28	2.0x
1P	151	131	+15%	185%	16.39	2.1x
2P	282	259	+9%	203%	16.27	2.1x

1) Baytex's reserves evaluated by McDaniel & Associates Consultants Ltd., an independent qualified reserves evaluator. Reserves categories: PDP – proved developed producing; 1P – proved; 2P – proved plus probable.
2) Production replacement is calculated by dividing reserves additions by annual production. Reserves additions includes extensions, technical revisions and economic factors.
3) F&D costs are calculated on a per boe basis by dividing the aggregate of the change in FDC from the prior year for the particular reserves category and the costs incurred on E&D activities in the year by the change in reserves from the prior year for the reserve category.
4) Recycle ratio is calculated by dividing operating netback on a per boe basis by F&D costs.

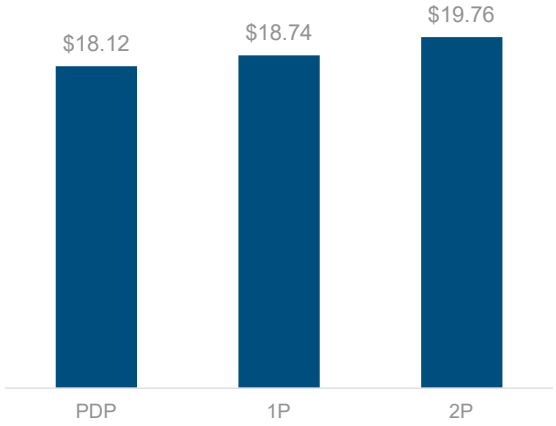
CANADIAN DEVELOPMENT PROGRAM DELIVERS CONSISTENT RESULTS

Strong production replacement, low F&D and healthy recycle ratios across all reserves categories[1]

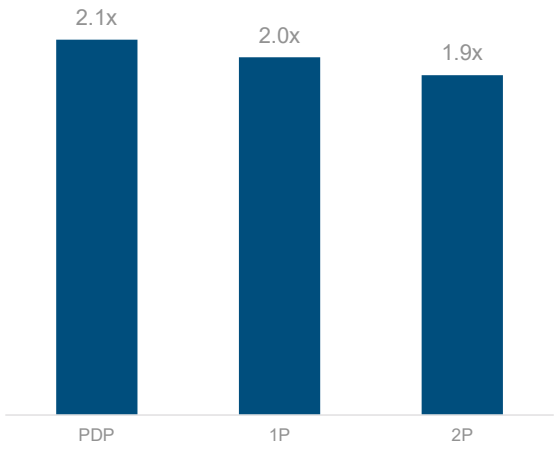
Production Replacement [2]
3 Year Average (2023-2025)



Finding & Development Costs (F&D) [3]
3 Year Average (2023-2025)



Recycle Ratio [4]
3 Year Average (2023-2025)



1) Baytex's reserves evaluated by McDaniel & Associates Consultants Ltd., an independent qualified reserves evaluator. Reserves categories: PDP – proved developed producing; 1P – proved; 2P – proved plus probable.
2) Production replacement is calculated by dividing reserves additions by annual production. Reserves additions includes extensions, technical revisions and economic factors.
3) F&D costs are calculated on a per boe basis by dividing the aggregate of the change in FDC from the prior year for the particular reserves category and the costs incurred on E&D activities in the year by the change in reserves from the prior year for the reserve category.
4) Recycle ratio is calculated by dividing operating netback on a per boe basis by F&D costs.

SUMMARY OF CANADIAN OPERATING AND FINANCIAL METRICS

	Q1 2024	Q2 2024	Q3 2024	Q4 2024	2024	Q1 2025	Q2 2025	Q3 2025	Q4 2025	2025	Q1 2026
Benchmark Prices											
WTI crude oil (US$/bbl)	$76.96	$80.57	$75.10	$70.27	**$75.72**	$71.42	$63.74	$63.74	$59.14	**$64.81**	$71.93
NYMEX natural gas (US$/MMbtu)	$2.24	$1.89	$2.16	$2.79	**$2.27**	$3.65	$3.44	$3.44	$3.55	**$3.43**	$5.04
Production											
Crude oil (bbl/d)	52,053	54,779	56,540	53,795	**54,296**	51,967	54,126	57,874	54,659	**54,672**	56,743
Natural gas liquids (bbl/d)	2,631	2,309	2,533	3,519	**2,749**	3,123	2,986	3,485	4,488	**3,524**	4,368
Natural gas (mcf/d)	44,380	39,599	33,566	48,113	**41,412**	43,743	42,331	40,961	48,895	**43,988**	50,205
Oil equivalent (boe/d) (1)	62,081	63,688	64,668	65,332	**63,948**	62,380	64,167	68,185	67,295	**65,528**	69,478
% Liquids	88%	90%	86%	88%	**89%**	88%	89%	90%	88%	**89%**	88%
Netback ($/boe)											
Total sales, net of blending and other expenses (2)	$62.33	$76.07	$72.37	$64.31	**$68.79**	$67.92	$59.71	$61.88	$53.55	**$60.61**	$60.30
Royalties (3)	(10.01)	(12.58)	(11.99)	(10.05)	**(11.16)**	(10.55)	(8.19)	(8.55)	(6.97)	**(8.52)**	(8.25)
Operating expense (3)	(15.12)	(14.57)	(14.69)	(13.12)	**(14.36)**	(13.46)	(15.08)	(13.55)	(13.84)	**(13.98)**	(12.99)
Transportation expense (3)	(3.22)	(3.38)	(4.17)	(3.59)	**(3.60)**	(3.34)	(3.52)	(3.68)	(3.44)	**(3.50)**	(3.70)
Operating Netback (2)	$33.98	$45.54	$41.52	$37.55	**$39.67**	$40.57	$32.92	$36.10	$29.30	**$34.61**	$35.36

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

2026 GUIDANCE AND COST ASSUMPTIONS

Exploration and development expenditures ($ millions)	~ $625
Production (boe/d)	69,000 - 71,000
Expenses:	
Average royalty rate (%) [1]	~ 15%
Operating ($/boe) [2]	$13.75 - $14.25
Transportation ($/boe) [2]	$3.40 - $3.60
Leasing expenditures ($ millions)	$7
Asset retirement obligations ($ millions)	$20

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 expense or transportation expense divided by barrels of oil equivalent production volume for the applicable period.

CRUDE OIL HEDGE PORTFOLIO

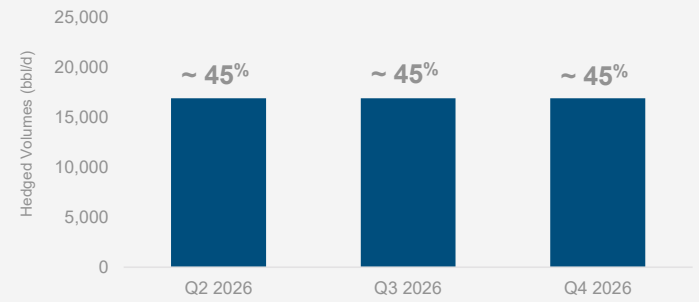
Managing WTI-WCS basis differential volatility

45% of heavy oil basis differential exposure hedged through 2026

WTI Hedges

Q2/2026 25,000 bbl/d (~50%) with US$60/bbl floor and US$66/bbl ceiling

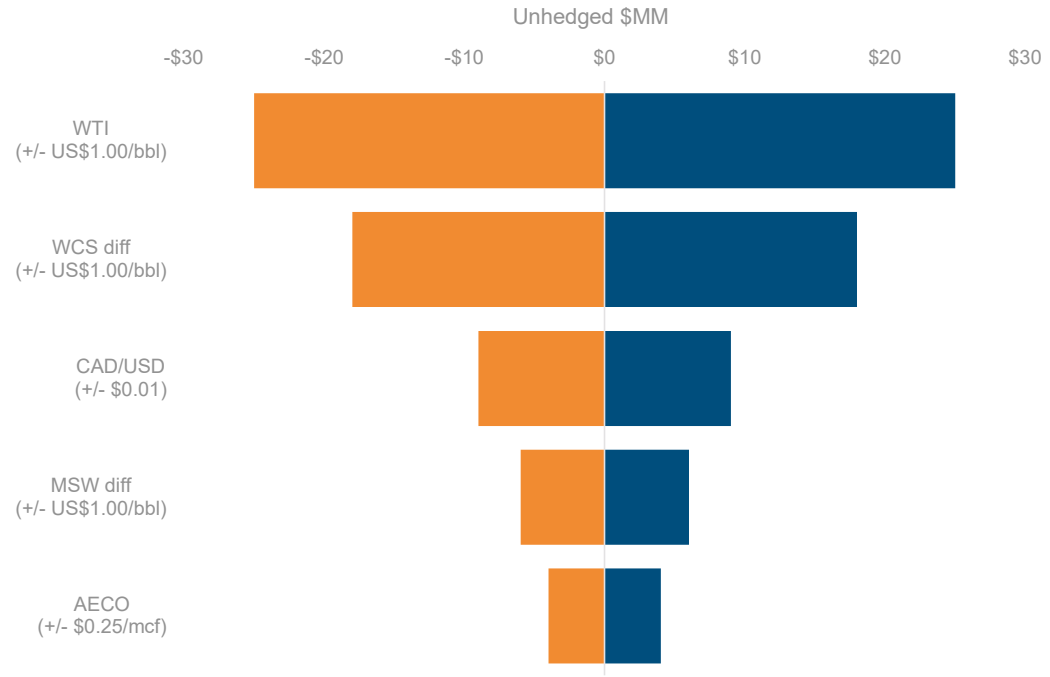
WTI-WCS Basis Differential Hedges (1)



	Q2 2026	Q3 2026	Q4 2026
WTI-WCS Differential (US$/bbl)	$13.06	$13.12	$13.20

1) Percentage of hedged volumes are based on 2026 production guidance, net of royalties.

2026 ADJUSTED FUNDS(1) FLOW SENSITIVITIES



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

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: a targeted annual total shareholder return of 15% at US$70 WTI, annual production growth of 6% to 8%, a long-term sustaining break-even target of under US$50/bbl WTI, Duvernay production of 20,000-25,000 by 2029-2030, advancement of heavy oil projects including first Peavine waterflood injection in June 2026 and potential final investment decision on our Gemini project in 2027; our capital allocation priorities including that a significant portion of our net cash position will be returned to shareholders prioritizing share buybacks and our intention to renew our NCIB for H2/2026; that Baytex will maintain its current dividend amount; Baytex's targeted annual production growth and production profile for 2026, expected capital expenditures in 2026 and allocation thereof; expected 2026 adjusted funds flow at certain WTI prices and the allocation thereof; Baytex's 3-year outlook including expected net operating income and production growth from heavy oil and the Pembina Duvernay, expectations regarding free cash flow generation from heavy oil, Baytex's net cash position and expectations for excess free cash flow; planned and potential exploration, development and production activities, including inventory support production rate, average break even WTI price and number of wells expected to be drilled in 2026 and beyond for the Pembina Duvernay; Baytex's anticipated upside in the Northeast Mannville; the design and expected wells per section of circulation string horizontal and multi-lateral horizontal wells; that Baytex could drill a Utikima exploration well in early 2027; plan to initiate 2 Peavine waterflood pilots in Q2/Q3 2026; the expected well economics of Baytex's Heavy Oil and Pembina Duvernay portfolio; estimated production growth for 2026 (to 2025), 2026 net debt to adjusted funds flow ratio and EV/DACF multiple; our 2026 guidance, including exploration and development expenditures, production, average royalty rate, expenses (operating and transportation), leasing expenditures and asset retirement obligations; and our anticipated 2026 adjusted funds flow sensitivities. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that they can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: oil and natural gas prices and differentials between light, medium and heavy crude oil prices; well production rates and reserve volumes; the duration and impact of tariffs that are currently in effect on goods exported from or imported into Canada, and that other than the tariffs that are currently in effect, neither the U.S. nor Canada (i) increases the rate or scope of such tariffs, reenacts tariffs that are currently suspended, or imposes new tariffs, on the import of goods from one country to the other, including on oil and natural gas, and/or (ii) imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; that we will have sufficient financial resources in the future to pursue our development plans and provide shareholder returns; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

FORWARD LOOKING STATEMENTS ADVISORY (CONT.)

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; 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; 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, 2025 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 exploration and development expenditures, estimated expenses for 2026 (including average royalty rate and operating and transportation expenses), estimated asset retirement obligations for 2026, allocation of cash to shareholder returns, net debt to adjusted funds flow ratio, free cash flow, adjusted funds flow and excess free cash flow, EV/DACF multiple, 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 presentation was made as of the date of this presentation 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. The payment of dividends to shareholders is not assured or guaranteed and dividends may be reduced or suspended entirely.

SPECIFIED FINANCIAL MEASURES ADVISORY

In this presentation, we refer to certain specified financial measures (such as free cash flow, operating netback, and total sales, net of blending and other expense) which do not have any standardized meaning prescribed by IFRS. While these measures are commonly used in the oil and 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 March 31, 2026, cash flows from operating activities was $122 million and free cash flow was $2 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 months ended March 31, 2026, which is incorporated herein by reference, and available on the SEDAR+ website at www.sedarplus.ca.

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 March 31, 2026, petroleum and natural gas sales for Canada was $453 million and operating netback for Canada was $221 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 months ended March 31, 2026, 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 March 31, 2026, petroleum and natural gas sales for Canada was $453 million and total sales, net of blending and other expense for Canada was $377 million. 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 months ended March 31, 2026, which is incorporated herein by reference, and available on the SEDAR+ website at www.sedarplus.ca.

Non-GAAP Financial Ratios

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 (cash) 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 (cash) 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 (cash) 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 March 31, 2026, credit facilities were nil and net cash was ($591 million). For the three months ended March 31, 2026, cash flows from operating activities were $122 million and adjusted funds flow was $151 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 months ended March 31, 2026, 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") and is based upon evaluations of Baytex's reserves prepared in accordance with NI 51-101 and the Canadian Oil and Gas Evaluation Handbook by McDaniel & Associates Consultants Ltd. effective each of December 31, 2023, December 31, 2024 and December 31, 2025. 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. It should not be assumed that the estimates of future net revenues presented herein represent the fair market value of the reserves. 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 2025 is included in our Annual Information Form for the year ended December 31, 2025 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 Duvernay, Baytex's net drilling locations include 58 proved and 11 probable locations as at December 31, 2025 and 141 unbooked locations. In the Viking, Baytex's net drilling locations include 457 proved and 196 probable locations as at December 31, 2025 and 263 unbooked locations. In the heavy oil business unit, Baytex's net drilling locations include 160 proved and 167 probable locations as at December 31, 2025 and 773 unbooked locations.

References herein to average 30-day initial production rates, "IP 365" 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.

This presentation contains a number of oil and gas and finance metrics, including "IP 365", "EUR", "DCET", "IRR", "Payout", "Recycle Ratio", "F&D Costs", "production replacement", "drilling efficiency", "operating netback", "CAGR" and others, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included herein to provide shareholders and potential investors with additional measures to evaluate Baytex's performance; however, such measures are not reliable indicators of the future performance of Baytex and future performance may not compare to the performance in previous periods and therefore such metrics should not be unduly relied upon. Management uses these oil and gas and finance metrics for its own performance measurements and to provide securityholders and potential investors with measures to compare Baytex's operations over time. Shareholders and potential investors are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this presentation, should not be relied upon for investment or other purposes.

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.

ADVISORY REGARDING OIL AND GAS INFORMATION

Peer and Industry Data

Certain peer and industry data contained in this presentation is based upon information from independent industry publications and reports or based on estimates derived from such publications and reports. Industry publications and reports generally indicate that they have obtained their information from sources believed to be reliable, but Baytex has not conducted its own independent verification of such information. Further, certain information contained in this presentation relating to Baytex's public issuer counterparties and the nature of their respective businesses is taken from and based solely upon information published by each such issuer. Baytex has not independently verified and does not assume any responsibility for the accuracy, completeness or reliability of such information.

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

CONTACT INFORMATION

BAYTEX ENERGY CORP.

Suite 2800, Centennial Place
520 – 3rd Avenue S.W.
Calgary, Alberta T2P 0R3
TF 1.800.524.5521
T 587.952.3237

Chad E. Lundberg
President and Chief Executive Officer

Chad L. Kalmakoff
Chief Financial Officer

Kendall D. Arthur
Chief Operating Officer

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