BAYTEX ANNOUNCES FOURTH QUARTER AND FULL YEAR 2024 FINANCIAL AND OPERATING RESULTS AND YEAR END RESERVES

CALGARY, ALBERTA (March 4, 2025) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three months and year ended December 31, 2024 (all amounts are in Canadian dollars unless otherwise noted).

"Our strong 2024 results speak to our disciplined, returns-based capital allocation philosophy that delivers increased per-share returns. In 2024, we generated 10% production per share growth and grew reserves per-share across all reserves categories. We executed our capital program on budget, generated meaningful free cash flow and returned $290 million to shareholders through our buyback program and quarterly dividend. For 2025, we will continue to prioritize free cash flow and shareholder returns," commented Eric T. Greager, President and Chief Executive Officer.

2024 Highlights

- Reported cash flows from operating activities of $469 million ($0.60 per basic share) in Q4/2024 and $1,908 million ($2.38 per basic share) for 2024.
- Increased production per basic share by 10% in 2024, compared to 2023. Production for the full-year 2024 averaged 153,048 boe/d (85% oil and NGL), compared to 122,154 boe/d in 2023 (85% oil and NGL). Production in Q4/2024 averaged 152,894 boe/d (84% oil and NGL).
- Delivered adjusted funds flow(1) of $462 million ($0.59 per basic share) in Q4/2024 and $1,957 million ($2.44 per basic share) for 2024.
- Generated free cash flow(2) of $255 million ($0.33 per basic share) in Q4/2024 and $656 million ($0.82 per basic share) for 2024.
- Returned $290 million to shareholders in 2024 through our share buyback program and dividend. We repurchased 48.4 million common shares for $218 million, representing 6% of our shares outstanding. In addition, we declared four quarterly dividends of $0.0225 per share, totaling $72 million.
- Improved our cash cost structure (operating, transportation, and general & administrative expenses) in 2024 by 5% on a boe basis, as compared to 2023.
- Reduced net debt(1) by 5% in 2024 (13% in U.S. dollars) and maintained balance sheet strength with a total debt to EBITDA ratio(3) of 1.1x.

Reserves Highlights (4)

- Achieved strong per-share growth and reserves replacement across all three reserves categories, proved developed producing ("PDP"), proved ("1P") and proved plus probable ("2P").
- Increased PDP reserves per share by 8% and 1P and 2P reserves per share by 6%. PDP reserves total 187 MMboe, 1P reserves total 408 MMboe and 2P reserves total 660 MMboe.
- Replaced 102% of production on a 1P basis and 101% of production on a 2P basis, excluding acquisition and divestiture activity.
- Generated a strong PDP recycle ratio of 1.9x and a 1P and 2P recycle ratio of 2.7x based on a 2024 operating netback(2) of $40.67/boe, reflective of the efficiency of our capital program and high netback oil-weighted portfolio.
- Increased our net asset value at year-end 2024, discounted at 10% before tax, 13% to $7.27 per share ($6.41 per share at year-end 2023). This is based on the estimated 2P reserves value, net of long-term debt and working capital.

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.
(3) Ratio is calculated as total debt at December 31, 2024 divided by EBITDA for the twelve months ended December 31, 2024. Total debt and EBITDA are calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.ca.
(4) 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").

	Three Months Ended			Twelve Months Ended	
	December 31, 2024	September 30, 2024	December 31, 2023	**December 31, 2024**	December 31, 2023
FINANCIAL (thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 1,017,017**	$ 1,074,623	$ 1,065,515	**$ 4,208,955**	$ 3,382,621
Adjusted funds flow (1)	**461,886**	537,947	502,148	**1,956,518**	1,594,350
Per share – basic	**0.59**	0.68	0.60	**2.44**	2.26
Per share – diluted	**0.59**	0.67	0.60	**2.42**	2.26
Free cash flow (2)	**254,838**	220,159	290,785	**655,582**	543,620
Per share – basic	**0.33**	0.28	0.35	**0.82**	0.77
Per share – diluted	**0.33**	0.28	0.35	**0.81**	0.77
Cash flows from operating activities	**468,865**	550,042	474,452	**1,908,264**	1,295,731
Per share – basic	**0.60**	0.69	0.57	**2.38**	1.84
Per share – diluted	**0.60**	0.69	0.57	**2.36**	1.84
Net income (loss)	**(38,477)**	185,219	(625,830)	**236,597**	(233,356)
Per share – basic	**(0.05)**	0.23	(0.75)	**0.29**	(0.33)
Per share – diluted	**(0.05)**	0.23	(0.75)	**0.29**	(0.33)
Dividends declared	**17,598**	17,732	18,381	**71,985**	37,519
Per share	**0.0225**	0.0225	0.0225	**0.090**	0.045
Capital Expenditures					
Exploration and development expenditures	**$ 198,177**	$ 306,332	$ 199,214	**$ 1,256,633**	$ 1,012,787
Acquisitions and (divestitures)	**(29,718)**	(394)	(125,822)	**5,920**	(121,342)
Total oil and natural gas capital expenditures	**$ 168,459**	$ 305,938	$ 73,392	**$ 1,262,553**	$ 891,445
Net Debt					
Credit facilities	**$ 341,207**	$ 466,108	$ 864,736	**$ 341,207**	$ 864,736
Long-term notes	**1,980,619**	1,856,869	1,597,475	**1,980,619**	1,597,475
Total debt (3)	**2,321,826**	2,322,977	2,462,211	**2,321,826**	2,462,211
Working capital deficiency (2)	**95,346**	170,292	72,076	**95,346**	72,076
Net debt (1)	**$ 2,417,172**	$ 2,493,269	$ 2,534,287	**$ 2,417,172**	$ 2,534,287
Shares Outstanding - basic (thousands)					
Weighted average	**782,131**	796,064	831,063	**803,435**	704,896
End of period	**773,590**	787,328	821,681	**773,590**	821,681
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 70.27**	$ 75.10	$ 78.32	**$ 75.72**	$ 77.62
MEH oil (US$/bbl)	**72.40**	77.50	80.62	**77.99**	79.29
MEH oil differential to WTI (US$/bbl)	**2.13**	2.40	2.30	**2.27**	1.67
Edmonton par ($/bbl)	**94.98**	97.91	99.72	**97.59**	100.46
Edmonton par differential to WTI (US$/bbl)	**(2.39)**	(3.30)	(5.10)	**(4.49)**	(3.18)
WCS heavy oil ($/bbl)	**80.77**	83.98	76.86	**83.56**	79.58
WCS differential to WTI (US$/bbl)	**(12.54)**	(13.51)	(21.88)	**(14.73)**	(18.65)
Natural gas					
NYMEX (US$/mmbtu)	**$ 2.79**	$ 2.16	$ 2.88	**$ 2.27**	$ 2.74
AECO ($/mcf)	**1.46**	0.81	2.66	**1.44**	2.93
CAD/USD average exchange rate	**1.3992**	1.3636	1.3619	**1.3700**	1.3495

Notes:

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

	Three Months Ended			Twelve Months Ended	
	December 31, 2024	September 30, 2024	December 31, 2023	**December 31, 2024**	December 31, 2023
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**64,661**	69,843	70,124	**66,894**	53,389
Heavy oil (bbl/d)	**42,227**	42,759	39,569	**42,313**	35,460
NGL (bbl/d)	**21,208**	19,836	23,160	**20,129**	14,304
Total liquids (bbl/d)	**128,096**	132,438	132,853	**129,336**	103,153
Natural gas (mcf/d)	**148,792**	132,175	165,121	**142,262**	114,010
Oil equivalent (boe/d @ 6:1) (1)	**152,894**	154,468	160,373	**153,048**	122,154
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense (2)	**$ 936,869**	$ 1,022,721	$ 1,003,219	**$ 3,945,012**	$ 3,157,819
Royalties	**(206,675)**	(223,800)	(228,570)	**(880,086)**	(669,792)
Operating expense	**(145,690)**	(167,119)	(164,873)	**(653,949)**	(570,839)
Transportation expense	**(33,110)**	(36,883)	(29,744)	**(133,142)**	(89,306)
Operating netback (2)	**$ 551,394**	$ 594,919	$ 580,032	**$ 2,277,835**	$ 1,827,882
General and administrative	**(20,433)**	(17,895)	(22,280)	**(81,746)**	(69,789)
Cash interest	**(48,769)**	(50,109)	(56,698)	**(206,104)**	(159,823)
Realized financial derivatives (loss) gain	**(2,115)**	331	12,377	**1,447**	36,212
Other (3)	**(18,191)**	10,701	(11,283)	**(34,914)**	(40,132)
Adjusted funds flow (4)	**$ 461,886**	$ 537,947	$ 502,148	**$ 1,956,518**	$ 1,594,350
Netback per boe (2)					
Total sales, net of blending and other expense (2)	**$ 66.60**	$ 71.97	$ 68.00	**$ 70.43**	$ 70.82
Royalties (5)	**(14.69)**	(15.75)	(15.49)	**(15.71)**	(15.02)
Operating expense (5)	**(10.36)**	(11.76)	(11.17)	**(11.67)**	(12.80)
Transportation expense (5)	**(2.35)**	(2.60)	(2.02)	**(2.38)**	(2.00)
Operating netback (2)	**$ 39.20**	$ 41.86	$ 39.32	**$ 40.67**	$ 41.00
General and administrative (5)	**(1.45)**	(1.26)	(1.51)	**(1.46)**	(1.57)
Cash interest (5)	**(3.47)**	(3.53)	(3.84)	**(3.68)**	(3.58)
Realized financial derivatives (loss) gain (5)	**(0.15)**	0.02	0.84	**0.03**	0.81
Other (3)	**(1.29)**	0.76	(0.78)	**(0.63)**	(0.90)
Adjusted funds flow (4)	**$ 32.84**	$ 37.85	$ 34.03	**$ 34.93**	$ 35.76

Notes:

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

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

(3) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and share-based compensation. Refer to the 2024 MD&A for further information on these amounts.

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

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

2025 Outlook

Baytex is a well-capitalized, North American oil-weighted producer with 60% of our production in the Eagle Ford in Texas and the balance in western Canada.

In 2025, the government of the United States of America announced tariffs on goods imported from Canada, including a 10% tariff on Canadian energy imports, effective March 4, 2025. We continue to monitor the impact of these tariffs and expect that our geographic diversification will provide a measure of insulation.

We are focused on disciplined capital allocation to prioritize free cash flow generation while maintaining a strong balance sheet. In the current commodity price environment this means moderating our growth profile and delivering stable crude oil production. We currently allocate approximately 50% of free cash flow(1) to the balance sheet and approximately 50% to shareholder returns, which includes a combination of share buybacks and quarterly dividend payments.

In 2025, we are targeting continued strong performance in the Eagle Ford, further progression of the Pembina Duvernay and capital efficient heavy oil development. We anticipate first quarter production of approximately 144,000 boe/d with volumes increasing over the balance of the year. During the first quarter, extremely cold temperatures across North America resulted in modest production disruptions across our operations. Our full year 2025 guidance is unchanged with exploration and development expenditures of $1.2 to $1.3 billion and production of 148,000 to 152,000 boe/d.

We expect to generate approximately $400 million of free cash flow in 2025 at US$70/bbl WTI. Based on our production profile and timing of capital expenditures, the majority of our free cash flow is expected to be generated in the second half of the year.

2024 Results

We delivered operating and financial results consistent with our full-year plan. Production and exploration and development expenditures were in line with full-year guidance and we improved our cash cost structure (operating, transportation, general & administrative expenses) by 5% on a boe basis, compared to 2023. Adjusted funds flow(2) totaled $2.0 billion ($2.44 per basic share) and we generated net income of $237 million ($0.29 per basic share).

We increased production per basic share by 10% in 2024, compared to 2023, with production averaging 153,048 boe/d (84% oil and NGL), up from 122,154 boe/d in 2023. Production in Q4/2024 averaged 152,894 boe/d (84% oil and NGL). Exploration and development expenditures totaled $1.26 billion in 2024 and we participated in the drilling of 290 (246.4 net) wells.

We generated free cash flow of $656 million ($0.82 per basic share) in 2024 and returned $290 million to shareholders through our share buyback program and dividend. We repurchased 48.4 million common shares for $218 million, representing 6% of our shares outstanding, at an average price of $4.50 per share. In addition, we declared four quarterly dividends of $0.0225 per share, totaling $72 million.

Over the last six quarters, we generated free cash flow of $1.1 billion and returned $550 million to shareholders through our share buyback program and dividend. We repurchased 88.9 million common shares for $440 million, representing 10% of our shares outstanding, at an average price of $4.95 per share. In addition, we declared six quarterly dividends of $0.0225 per share, totaling $110 million.

On December 20, 2024, we completed the divestiture of our Kerrobert thermal asset in southwest Saskatchewan for net proceeds of $41.5 million. Proceeds from the sale were applied against our credit facilities. Production from the assets at the time of the sale was approximately 2,000 bbl/d (100% heavy oil).

We reduced net debt(2) by 5% ($117 million) in 2024. Our strong free cash flow generation was significantly offset by the impact of a strengthening U.S. dollar, relative to the Canadian dollar, on our U.S. dollar denominated debt. In U.S. dollars, we reduced net debt by 13% (US$241 million). On an annual basis, a $0.05 CAD/USD change in the foreign exchange rate impacts our net debt by approximately $70 million.

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

Operations

In the Eagle Ford, production averaged 89,100 boe/d (81% oil and NGL) in 2024 and we brought onstream 64 net wells, including 51 net operated wells. Our development program was largely focused on the black oil and volatile oil windows of our acreage where we typically generate 30-day peak crude oil rates of 700 to 800 bbl/d (900 to 1,100 boe/d) per well with average lateral lengths of 9,000 to 9,500 feet. We realized an 8% improvement in operated drilling and completion costs per completed lateral foot over 2023.

In the Eagle Ford, we expect to bring onstream 54 net wells in 2025, including 41 net operated wells. We intend to run a consistent two rig and one frac crew program for most of the year and are targeting a 7% improvement in operated drilling and completion costs per completed lateral foot compared to 2024.

In our Canadian light oil business unit, production averaged 16,701 boe/d (83% oil and NGL) in 2024. We made substantial strides in advancing our understanding of the Pembina Duvernay with production increasing 64% to 6,112 boe/d (82% oil and NGL) in 2024, compared to 2023. We brought onstream seven net wells in the Pembina Duvernay and 95 net wells in the the Viking. In 2025, we expect to bring onstream nine net wells in the Pembina Duvernay and 90 net wells in the Viking.

In our heavy oil business unit, production averaged 43,704 boe/d (95% oil and NGL) in 2024. Peavine continued to deliver top well results with production increasing 44% to 19,241 bbl/d (100% heavy oil) in 2024, compared to 2023. During 2024, we brought onstream 31 net Clearwater wells at Peavine, 9 net wells at Peace River and 40 net wells across the broader Mannville group in Lloydminster. In 2025, we expect to bring onstream 112 net heavy oil wells, including 33 net Clearwater wells at Peavine.

Subsequent to year-end, we acquired through an asset exchange, 44.5 net sections of land on the Peavine Métis settlement. The lands acquired are immediately adjacent to our existing 90-section acreage position.

Quarterly Dividend

The Board of Directors has declared a quarterly cash dividend of $0.0225 per share to be paid on April 1, 2025 for shareholders of record on March 14, 2025.

Year-end 2024 Reserves

Baytex's year-end 2024 reserves were evaluated by McDaniel & Associates Consultants Ltd. (“McDaniel”), an independent qualified reserves evaluator. All of our oil and gas properties were evaluated in accordance with National Instrument 51-101 “Standards of Disclosure for Oil and Gas Activities” (“NI 51-101”) and the Canadian Oil and Gas Evaluation Handbook (the “COGE Handbook”) using the average commodity price forecasts and inflation rates of McDaniel, GLJ Petroleum Consultants (“GLJ”) and Sproule Associates Limited (“Sproule”) as of January 1, 2025.

For additional information regarding Baytex's reserves as at December 31, 2024, see Baytex's Annual Information Form for the year ended December 31, 2024 on Baytex's SEDAR+ profile at www.sedarplus.ca, and Baytex's U.S. Form 40-F for the year ended December 31, 2024 on EDGAR at www.sec.gov, each of which are anticipated to be filed on March 4, 2025.

Reserves Summary

- We achieved strong reserves replacement and per-share growth across all three reserves categories, proved developed producing ("PDP") , proved ("1P") and proved plus probable ("2P").
- We invested $1.26 billion on exploration and development expenditures in 2024 and replaced 102% of production on a 1P basis and 101% of production on a 2P basis, excluding acquisition and divestiture activity. In 2024, we divested our Kerrobert thermal asset which reduced 1P and 2P reserves by 2.9 MMboe and 4.2 MMboe, respectively.
- PDP reserves per share increased 8% and 1P and 2P reserves per share increased 6%. PDP reserves total 187 MMboe (185 MMboe at year-end 2023), 1P reserves total 408 MMboe (410 MMboe at year-end 2023) and 2P reserves total 660 MMboe (663 MMboe at year-end 2023).
- We generated a strong PDP recycle ratio of 1.9x and a 1P and 2P recycle ratio of 2.7x based on a 2024 operating netback(1) of $40.67/boe, reflective of the efficiency of our capital program and high netback oil-weighted portfolio.
- Finding and development ("F&D") costs, including changes in future development costs (“FDC”), were $21.32/boe for PDP reserves, $15.06/boe for 1P reserves and $14.81/boe for 2P reserves.
- At year-end 2024, the present value of our reserves, discounted at 10% before tax, is estimated to be $5.0 billion ($5.0 billion at year-end 2023) on a 1P basis and $8.0 billion ($7.8 billion at year-end 2023) on a 2P basis.
- Our net asset value at year-end 2024, discounted at 10% before tax, increased 13% to $7.27 per share ($6.41 per share at year-end 2023). This is based on the estimated 2P reserves value, net of long-term debt and working capital.
- Our booked drilling locations within 2P reserves represents approximately 52% of our 2,911 net risked drilling locations in inventory.
- FDC on a 1P basis decreased to $5.6 billion ($6.0 billion at year-end 2023) and on a 2P basis, decreased to $8.6 billion ($9.1 billion at year-end 2023), largely attributable to reduced drilling and completion costs in the Eagle Ford.
- Reserves on a 1P basis are comprised of 83% oil and NGLs (47% light oil, 22% NGLs and 14% heavy oil) and 17% natural gas.
- Baytex maintains a strong reserves life index of 7.5 years based on 1P reserves and 12.1 years based on 2P reserves (using the mid-point of 2025 production guidance).

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

The following table sets forth our gross and net reserves volumes at December 31, 2024 by product type and reserves category. Please note that the data in the table may not add due to rounding.

Reserves Summary

Reserves Summary	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids [3] (Mbbls)	Conventional Natural Gas [4] (MMcf)	Shale Gas (MMcf)	Total [5] (Mboe)
Gross [1]									
Proved producing	9,131	73,924	34,250	—	117,305	37,317	48,570	146,964	187,211
Proved developed non-producing	352	1,517	2,024	—	3,893	1,489	1,596	4,302	6,364
Proved undeveloped	14,122	92,759	19,082	—	125,963	53,117	24,623	188,509	214,602
Total proved	23,604	168,200	55,357	—	247,161	91,923	74,789	339,775	408,177
Total probable	13,644	84,798	34,190	44,489	177,121	42,813	38,344	152,995	251,824
Proved plus probable	37,248	252,998	89,547	44,489	424,281	134,736	113,133	492,770	660,001
Net [2]									
Proved producing	8,662	56,721	28,915	—	94,298	28,620	44,240	113,214	149,160
Proved developed non-producing	329	1,121	1,808	—	3,257	1,108	1,494	3,188	5,145
Proved undeveloped	13,362	72,117	16,720	—	102,200	41,121	21,496	147,217	171,440
Total proved	22,353	129,958	47,443	—	199,754	70,849	67,231	263,618	325,745
Total probable	12,670	65,263	28,224	34,897	141,054	33,290	33,877	120,376	200,052
Proved plus probable	35,023	195,221	75,667	34,897	340,808	104,139	101,107	383,994	525,797

Notes:

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

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

(3) Natural Gas Liquids includes condensate.

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

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

Reserves Reconciliation

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

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

	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (2) (Mbbls)	Conventional Natural Gas (3) (MMcf)	Shale Gas (MMcf)	Total (4) (Mboe)
December 31, 2023	25,803	162,782	51,078	3,783	243,447	94,840	77,910	353,924	410,259
Extensions	1,496	18,691	12,064	—	32,251	9,809	4,256	40,792	49,568
Technical Revisions	(498)	7,592	6,163	—	13,257	(4,574)	6,227	(14,867)	7,243
Acquisitions	—	—	383	—	383	—	—	—	383
Dispositions	—	(207)	(109)	(2,941)	(3,257)	(68)	(8)	(345)	(3,384)
Economic Factors	70	(54)	422	—	438	(105)	(892)	(366)	123
Production	(3,266)	(20,605)	(14,645)	(842)	(39,358)	(7,979)	(12,704)	(39,363)	(56,015)
December 31, 2024	23,604	168,200	55,357	—	247,161	91,923	74,789	339,775	408,177

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

	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (2) (Mbbls)	Conventional Natural Gas (3) (MMcf)	Shale Gas (MMcf)	Total (4) (Mboe)
December 31, 2023	14,997	85,238	32,935	45,754	178,923	42,334	38,246	151,764	252,925
Extensions	276	1,689	2,509	—	4,474	1,603	2,270	7,419	7,692
Technical Revisions	(1,646)	(1,964)	(1,759)	(27)	(5,396)	(1,050)	(1,625)	(5,884)	(7,699)
Acquisitions	—	—	518	—	518	—	—	—	518
Dispositions	—	(146)	(36)	(1,238)	(1,420)	(48)	(2)	(225)	(1,507)
Economic Factors	17	(18)	23	—	22	(24)	(545)	(79)	(106)
Production	—	—	—	—	—	—	—	—	—
December 31, 2024	13,644	84,798	34,190	44,489	177,121	42,813	38,344	152,995	251,824

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

	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (2) (Mbbls)	Conventional Natural Gas (3) (MMcf)	Shale Gas (MMcf)	Total (4) (Mboe)
December 31, 2023	40,799	248,020	84,013	49,537	422,370	137,173	116,156	505,688	663,184
Extensions	1,772	20,380	14,573	—	36,725	11,412	6,526	48,212	57,260
Technical Revisions	(2,144)	5,627	4,404	(27)	7,860	(5,624)	4,601	(20,752)	(456)
Acquisitions	—	—	901	—	901	—	—	—	901
Dispositions	—	(353)	(145)	(4,179)	(4,677)	(116)	(10)	(570)	(4,890)
Economic Factors	87	(72)	445	—	460	(130)	(1,436)	(445)	17
Production	(3,266)	(20,605)	(14,645)	(842)	(39,358)	(7,979)	(12,704)	(39,363)	(56,015)
December 31, 2024	37,248	252,997	89,547	44,489	424,281	134,736	113,133	492,770	660,001

Notes:
(1) "Gross" reserves means the total working interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.
(2) Natural gas liquids includes condensate.
(3) Conventional natural gas includes associated, non-associated and solution gas.
(4) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Future Development Costs

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

Future Development Costs ($ millions)	Proved Reserves	Proved Plus Probable Reserves
2025	1,079	1,155
2026	1,081	1,214
2027	1,296	1,478
2028	1,317	1,512
2029	731	1,354
Remainder	53	1,896
Total FDC undiscounted	5,556	8,608

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

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

$ millions except for per boe amounts	2024	2023	2022	3 Year
Proved plus Probable Reserves				
Finding & Development Costs				
Exploration and development expenditures	$ 1,256.6	$ 1,012.8	$ 521.5	$ 2,791.0
Net change in Future Development Costs	$ (415.5)	$ 841.2	$ 588.6	$ 1,014.4
Gross Reserves additions (MMboe)	56.8	64.6	26.2	147.6
F&D Costs ($/boe)	$ 14.81	$ 28.68	$ 42.34	$ 25.77
Finding, Development & Acquisition (“FD&A”) Costs				
Exploration and development expenditures and net acquisitions	$ 1,262.6	$ 3,948.5	$ 497.2	$ 5,708.3
Net change in Future Development Costs	$ (443.0)	$ 4,763.6	$ 537.6	$ 4,858.1
Gross Reserves additions (MMboe)	52.8	270.2	17.2	340.2
FD&A Costs ($/boe)	$ 15.51	$ 32.25	$ 60.05	$ 31.06
Proved Reserves				
Finding & Development Costs				
Exploration and development expenditures	$ 1,256.6	$ 1,012.8	$ 521.5	$ 2,791.0
Net change in Future Development Costs	$ (399.4)	$ 491.7	$ 320.1	$ 412.4
Gross Reserves additions (MMboe)	56.9	50.5	21.4	128.7
F&D Costs ($/boe)	$ 15.06	$ 29.82	$ 39.40	$ 24.89
Finding, Development & Acquisition Costs				
Exploration and development expenditures and net acquisitions	$ 1,262.6	$ 3,948.5	$ 497.2	$ 5,708.3
Net change in Future Development Costs	$ (430.0)	$ 3,290.6	$ 285.0	$ 3,145.6
Gross Reserves additions (MMboe)	53.9	190.6	16.6	261.0
FD&A Costs ($/boe)	$ 15.46	$ 37.98	$ 47.25	$ 33.92
Proved Developed Producing Reserves				
Finding & Development Costs				
Exploration and development expenditures	$ 1,256.6	$ 1,012.8	$ 521.5	$ 2,791.0
Gross Reserves additions (MMboe)	58.9	41.8	27.2	127.9
F&D Costs ($/boe)	$ 21.32	$ 24.23	$ 19.20	$ 21.82
Finding, Development & Acquisition Costs				
Exploration and development expenditures and net acquisitions	$ 1,262.6	$ 3,948.5	$ 497.2	$ 5,708.3
Gross Reserves additions (MMboe)	57.9	104.8	26.0	188.6
FD&A Costs ($/boe)	$ 21.81	$ 37.69	$ 19.13	$ 30.26

Forecast Prices and Costs

The following table summarizes the forecast prices used in preparing the estimated reserves volumes and the net present values of future net revenues at December 31, 2024. The estimated future net revenue to be derived from the production of the reserves is based on the following average of the price forecasts of McDaniel, GLJ and Sproule as of January 1, 2025.

Year	WTI Crude Oil US$/bbl	Edmonton Light Crude Oil $/bbl	Western Canadian Select $/bbl	Henry Hub US$/MMbtu	AECO Spot $/MMbtu	Inflation Rate %/Yr	Exchange Rate $US/$Cdn
2024 act.	76.55	97.50	83.60	2.20	1.45	2.4	0.730
2025	71.58	94.79	82.69	3.31	2.36	—	0.712
2026	74.48	97.04	84.27	3.73	3.33	2.0	0.728
2027	75.81	97.37	83.81	3.85	3.48	2.0	0.743
2028	77.66	99.80	85.70	3.93	3.69	2.0	0.743
2029	79.22	101.79	87.45	4.01	3.76	2.0	0.743
2030	80.80	103.83	89.25	4.09	3.83	2.0	0.743
2031	82.42	105.91	91.04	4.17	3.91	2.0	0.743
2032	84.06	108.03	92.85	4.26	3.99	2.0	0.743
2033	85.74	110.19	94.71	4.34	4.07	2.0	0.743
2034	87.46	112.39	96.61	4.43	4.15	2.0	0.743
Thereafter		Escalation rate of 2.0%				2.0	0.743

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

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

Reserves at December 31, 2024 ($ millions, discounted at)	0%	5%	10%	15%
Proved developed producing	3,665	3,751	3,389	3,054
Proved developed non-producing	235	171	138	117
Proved undeveloped	3,702	2,338	1,519	989
Total proved	7,602	6,260	5,046	4,159
Probable	8,242	4,672	2,997	2,093
Total Proved Plus Probable (before tax)	15,844	10,932	8,043	6,252

Note:

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

Additional Information

Our audited consolidated financial statements for the year ended December 31, 2024 and the related Management's Discussion and Analysis of the operating and financial results can be accessed on our website at www.baytexenergy.com and will be available shortly through SEDAR+ at www.sedarplus.ca and EDGAR at www.sec.gov.

Conference Call Tomorrow
9:00 a.m. MST (11:00 a.m. EST)

Baytex will host a conference call tomorrow, March 5, 2025, starting at 9:00am MST (11:00am EST). To participate, please dial toll free in North America 1-844-763-8274 or international 1-647-484-8814. Alternatively, to listen to the conference call online, please enter https://event.choruscall.com/mediaframe/webcast.html?webcastid=zgaTXTCO in your web browser.

An archived recording of the conference call will be available shortly after the event by accessing the webcast link above. The conference call will also be archived on the Baytex website at www.baytexenergy.com.

Advisory Regarding Forward-Looking Statements

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

Specifically, this press release contains forward-looking statements relating to but not limited to: for 2025, that we will prioritize free cash flow and shareholder returns; that we expect to be insulated from tariffs as a result of our geographic diversification; our intention to allocate free cash flow to each of debt repayment and shareholder returns (including share buybacks and quarterly dividends) and the expected allocation of such free cash flow; our development plans for 2025, our expected Q1/2025 and full-year production volumes and full year exploration and development expenditures; our anticipated free cash flow for 2024 and that the majority is expected to be generated in H2/2025; the anticipated impact of the CAD/US exchange rate on our net debt; our 2025 drilling plans, including the number of net wells we intend to bring online and our targeted 7% improvement in operated drilling and completion costs in the operated Eagle Ford; future development costs, F&D and FD&A; forecast prices for oil and natural gas; forecast inflation and exchange rates; and the net present value before income taxes of the future net revenue attributable to our reserves. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that they can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: oil and natural gas prices and differentials between light, medium and heavy crude oil prices; well production rates and reserve volumes; success obtained in drilling new wells; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; operating costs; our ability to borrow under our credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; our ability to market oil and natural gas successfully; that we will have sufficient financial resources in the future to provide shareholder returns; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the risk of an extended period of low oil and natural gas prices (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.

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

These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2024, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission on March 4, 2024 and in our other public filings. The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

This press release contains information that may be considered a financial outlook under applicable securities laws about the Corporation's potential financial position, including, but not limited to, our 2025 guidance for development expenditures; our expected 2025 free cash flow; and our intentions of allocating our annual free cash flow to shareholder returns through a share buyback and debt reduction; all of which are subject to numerous assumptions, risk factors, limitations and qualifications, including those set forth in the above paragraphs. The actual results of operations of the Corporation and the resulting financial results will vary from the amounts set forth in this press release and such variations may be material. This information has been provided for illustration only and with respect to future periods are based on budgets and forecasts that are speculative and are subject to a variety of contingencies and may not be appropriate for other purposes. Accordingly, these estimates are not to be relied upon as indicative of future results. Except as required by applicable securities laws, the Corporation undertakes no obligation to update such financial outlook, whether as a result of new information, future events or otherwise. The financial outlook contained in this press release was made as of the date of this press release and was provided for the purpose of providing further information about the Corporation's potential future business operations. Readers are cautioned that the financial outlook contained in this press release is not conclusive and is subject to change.

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

<u>Specified Financial Measures</u>

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

Non-GAAP Financial Measures

Total sales, net of blending and other expense

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

Operating netback

Operating netback is used to assess our operating performance and our ability to generate cash margin on a unit of production basis. Operating netback is comprised of petroleum and natural gas sales, less blending expense, royalties, operating expense and transportation expense.

The following table reconciles operating netback to petroleum and natural gas sales.

	Three Months Ended			Years Ended December 31	
($ thousands)	**December 31, 2024**	September 30, 2024	December 31, 2023	**2024**	2023
Petroleum and natural gas sales	**$ 1,017,017**	$ 1,074,623	$ 1,065,515	**$ 4,208,955**	$ 3,382,621
Blending and other expense	**(80,148)**	(51,902)	(62,296)	**(263,943)**	(224,802)
Total sales, net of blending and other expense	**$ 936,869**	$ 1,022,721	$ 1,003,219	**$ 3,945,012**	$ 3,157,819
Royalties	**(206,675)**	(223,800)	(228,570)	**(880,086)**	(669,792)
Operating expense	**(145,690)**	(167,119)	(164,873)	**(653,949)**	(570,839)
Transportation expense	**(33,110)**	(36,883)	(29,744)	**(133,142)**	(89,306)
Operating netback	**$ 551,394**	$ 594,919	$ 580,032	**$ 2,277,835**	$ 1,827,882

Free cash flow

We use free cash flow to evaluate our financial performance and to assess the cash available for debt repayment, common share repurchases, dividends and acquisition opportunities. Free cash flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital, transaction costs, additions to exploration and evaluation assets, additions to oil and gas properties, payments on lease obligations, and cash premiums on derivatives.

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

	Three Months Ended			Years Ended December 31	
($ thousands)	**December 31, 2024**	September 30, 2024	December 31, 2023	**2024**	2023
Cash flows from operating activities	**$ 468,865**	$ 550,042	$ 474,452	**$ 1,908,264**	$ 1,295,731
Change in non-cash working capital	**(13,428)**	(20,813)	14,971	**17,922**	220,895
Transaction costs	**—**	—	5,079	**1,539**	49,045
Additions to exploration and evaluation assets	**—**	—	1,271	**—**	—
Additions to oil and gas properties	**(198,177)**	(306,332)	(200,537)	**(1,256,633)**	(1,012,787)
Payments on lease obligations	**(2,422)**	(2,738)	(4,451)	**(15,510)**	(11,527)
Cash premiums on derivatives	**—**	—	—	**—**	2,263
Free cash flow	**$ 254,838**	$ 220,159	$ 290,785	**$ 655,582**	$ 543,620

Working capital deficiency

Working capital deficiency is calculated as cash, trade receivables, and prepaids and other assets net of trade payables, dividends payable, other long-term liabilities and share-based compensation liability. Working capital deficiency is used by management to measure the Company's liquidity. At December 31, 2024, the Company had $1.2 billion of available credit facility capacity to cover any working capital deficiencies.

The following table summarizes the calculation of working capital deficiency.

	As at		
($ thousands)	**December 31, 2024**	September 30, 2024	December 31, 2023
Cash	**$ (16,610)**	$ (21,311)	$ (55,815)
Trade receivables	**(387,266)**	(375,942)	(339,405)
Prepaids and other assets	**(76,468)**	(78,427)	(83,259)
Trade payables	**512,473**	584,696	477,295
Share-based compensation liability	**24,732**	23,962	35,732
Other long-term liabilities	**20,887**	19,582	19,147
Dividends payable	**17,598**	17,732	18,381
Working capital deficiency	**$ 95,346**	$ 170,292	$ 72,076

Non-GAAP Financial Ratios

Total sales, net of blending and other expense per boe

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

Operating netback per boe

Operating netback per boe is equal to operating netback (a non-GAAP financial measure) divided by barrels of oil equivalent sales volume for the applicable period and is used to assess our operating performance on a unit of production basis.

Capital Management Measures

Net debt

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

The following table summarizes our calculation of net debt.

	As at		
($ thousands)	**December 31, 2024**	September 30, 2024	December 31, 2023
Credit facilities	**$ 324,346**	$ 449,116	$ 848,749
Unamortized debt issuance costs - Credit facilities (1)	**16,861**	16,992	15,987
Long-term notes	**1,932,890**	1,810,701	1,562,361
Unamortized debt issuance costs - Long-term notes (1)	**47,729**	46,168	35,114
Trade payables	**512,473**	584,696	477,295
Share-based compensation liability	**24,732**	23,962	35,732
Dividends payable	**17,598**	17,732	18,381
Other long-term liabilities	**20,887**	19,582	19,147
Cash	**(16,610)**	(21,311)	(55,815)
Trade receivables	**(387,266)**	(375,942)	(339,405)
Prepaids and other assets	**(76,468)**	(78,427)	(83,259)
Net debt	**$ 2,417,172**	$ 2,493,269	$ 2,534,287

(1) Unamortized debt issuance costs were obtained from Note 8 Credit Facilities and Note 9 Long-term Notes from the Consolidated Financial Statements for the year ended December 31, 2024.

Adjusted funds flow

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

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

	Three Months Ended			Years Ended December 31	
($ thousands)	**December 31, 2024**	September 30, 2024	December 31, 2023	**2024**	2023
Cash flows from operating activities	**$ 468,865**	$ 550,042	$ 474,452	**$ 1,908,264**	$ 1,295,731
Change in non-cash working capital	**(13,428)**	(20,813)	14,971	**17,922**	220,895
Asset retirement obligations settled	**6,449**	8,718	7,646	**28,793**	26,416
Transaction costs	**—**	—	5,079	**1,539**	49,045
Cash premiums on derivatives	**—**	—	—	**—**	2,263
Adjusted funds flow	**$ 461,886**	$ 537,947	$ 502,148	**$ 1,956,518**	$ 1,594,350

Advisory Regarding Oil and Gas Information

The reserves information contained in this press release has been prepared in accordance with NI 51-101. Complete NI 51-101 reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2024, which will be filed on March 4, 2025. Listed below are cautionary statements that are specifically required by NI 51-101:

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

This press release discloses drilling inventory and potential drilling locations. Drilling inventory and drilling locations refers to Baytex's proved, probable and unbooked locations. Proved locations and probable locations account for drilling locations in our inventory that have associated proved and/or probable reserves. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves. Unbooked locations are farther away from existing wells and, therefore, there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty whether such wells will result in additional oil and gas reserves, resources or production. In the Eagle Ford, Baytex's net drilling locations include 331 proved and 140 probable locations as at December 31, 2024 and 294 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. 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 Duvernay, Baytex's net drilling locations include 42 proved and 20 probable locations as at December 31, 2024 and 180 unbooked locations.*

Throughout this press release, "oil and NGL" refers to heavy oil, bitumen, light and medium oil, tight oil, condensate and natural gas liquids ("NGL") product types as defined by NI 51-101. The following table shows Baytex's disaggregated production volumes for the three and twelve months ended December 31, 2024. The NI 51-101 product types are included as follows: "Heavy Oil" - heavy oil and bitumen, "Light and Medium Oil" - light and medium oil, tight oil and condensate, "NGL" - natural gas liquids and "Natural Gas" - shale gas and conventional natural gas.

	Three Months Ended December 31, 2024					Twelve Months Ended December 31, 2024				
	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada – Heavy										
Peace River	9,380	9	26	9,976	11,078	9,250	10	37	10,691	11,080
Lloydminster	12,848	15	—	1,267	13,074	13,119	16	—	1,491	13,383
Peavine	19,333	—	—	—	19,333	19,241	—	—	—	19,241
Canada - Light										
Viking	24	7,916	194	9,486	9,715	6	8,717	187	10,075	10,589
Duvernay	—	3,418	2,536	7,918	7,273	—	2,941	2,054	6,700	6,112
Remaining Properties	642	210	763	19,466	4,859	697	300	471	12,455	3,544
United States										
Eagle Ford	—	53,093	17,689	100,679	87,562	—	54,911	17,380	100,850	89,100
Total	42,227	64,661	21,208	148,792	152,894	42,313	66,894	20,129	142,262	153,048

This press release contains metrics commonly used in the oil and natural gas industry, such as "finding and development costs", "finding, development and acquisition costs", "PDP recycle ratio", "1P recycle ratio", and "2P recycle ratio". These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included in this press release to provide readers with additional measures to evaluate Baytex's performance, however, such measures are not reliable indicators of Baytex's future performance and future performance may not compare to Baytex's performance in previous periods and therefore such metrics should not be unduly relied upon.

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

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

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

Notice to United States Readers

The petroleum and natural gas reserves contained in this press release have generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. For example, the United States Securities and Exchange Commission (the "SEC") requires oil and gas issuers, in their filings with the SEC, to disclose only "proved reserves", but permits the optional disclosure of "probable reserves" (each as defined in SEC rules). Canadian securities laws require oil and gas issuers disclose their reserves in accordance with NI 51-101, which requires disclosure of not only "proved reserves" but also "probable reserves". Additionally, NI 51-101 defines "proved reserves" and "probable reserves" differently from the SEC rules. Accordingly, proved and probable reserves disclosed in this press release 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 press release may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

Baytex Energy Corp.

Baytex Energy Corp. is an energy company based in Calgary, Alberta. The company is engaged in the acquisition, development and production of crude oil and natural gas in the Western Canadian Sedimentary Basin and in the Eagle Ford in the United States. Approximately 85% of Baytex's production is weighted toward crude oil and natural gas liquids. Baytex's common shares trade on the Toronto Stock Exchange and the New York Stock Exchange under the symbol BTE.

For further information about Baytex, please visit our website at www.baytexenergy.com or contact:

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