

2025 Management's Discussion and Analysis

The following management's discussion and analysis ("MD&A") as provided by the management of Headwater Exploration Inc. ("Headwater" or the "Company") is dated March 5, 2026, and should be read in conjunction with the audited annual financial statements for the years ended December 31, 2025 and 2024 and the notes thereto. The audited annual financial statements have been prepared in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board ("IFRS"). All dollar amounts are referenced in Canadian dollars unless otherwise stated. In addition, readers are also directed to the Company's Annual Information Form for the year ended December 31, 2025, dated March 5, 2026, which is available on the Company's website at www.headwaterexp.com and through SEDAR+ at www.sedarplus.ca.

Description of the Company

Headwater is a Canadian resource company engaged in the exploration for and development and production of petroleum and natural gas in Canada. The majority of Headwater's heavy oil production and reserves are primarily located in the Clearwater, Grand Rapids and Wabiskaw formations in the greater Marten Hills area of Alberta, while the Company also has natural gas production and reserves in the McCully field near Sussex, New Brunswick.

Unless otherwise indicated herein, all production information presented herein has been presented on a gross basis, which is the Company's working interest prior to deduction of royalties and without including any royalty interests.

FOURTH QUARTER 2025 HIGHLIGHTS

- Achieved record average production of 24,259 boe/d, representing an increase of 13% over 2024 fourth quarter production of 21,559 boe/d.
- Realized adjusted funds flow from operations ⁽¹⁾ of \$79.3 million (\$0.33 per basic share ⁽²⁾) and cash flows from operating activities of \$72.7 million (\$0.31 per basic share).
- Achieved an operating netback, including financial derivatives ⁽²⁾ of \$41.14/boe and an adjusted funds flow netback ⁽²⁾ of \$35.65/boe.
- Generated net income of \$29.3 million (\$0.12 per basic share) equating to \$13.18/boe
- Executed a \$46.1 million capital expenditure ⁽³⁾ program inclusive of development, exploration and secondary recovery implementation.
- Returned \$0.11 per common share, or \$26.2 million, to shareholders through dividends.
- As at December 31, 2025, Headwater had working capital of \$30.0 million, adjusted working capital ⁽¹⁾ of \$23.6 million and no outstanding bank debt.

YEAR ENDED DECEMBER 31, 2025 HIGHLIGHTS

- Achieved record average production of 22,776 boe/d, representing an increase of 12% over 2024 annual production of 20,310 boe/d.
- Realized adjusted funds flow from operations ⁽¹⁾ of \$326.2 million (\$1.37 per basic share ⁽²⁾) and cash flows from operating activities of \$297.1 million (\$1.25 per basic share).
- Achieved an operating netback, including financial derivatives ⁽²⁾ of \$45.22/boe and an adjusted funds flow netback ⁽²⁾ of \$39.27/boe.
- Generated net income of \$153.2 million (\$0.64 per basic share) equating to \$18.44/boe.
- Executed a \$228.3 million capital expenditure ⁽³⁾ program:
 - Drilled 61.0 net crude oil wells during the year ended December 31, 2025;
 - Continued to pursue secondary recovery efforts with more than 50% of Headwater's oil production supported by secondary recovery at December 31, 2025; and
 - Achieved exploration success with material discoveries in the Grand Rapids formation at Marten Hills West and a new operating area at Greater Pelican.
- Returned a total of \$0.44 per common share, or \$104.7 million, to shareholders through dividends. The Company increased its quarterly cash dividend to \$0.11 per common share (\$0.44 per common share annualized) effective for the dividend paid on April 15, 2025, to shareholders of record at the close of business on March 31, 2025. To date, Headwater has paid out cumulative dividends of \$317.6 million to shareholders (\$1.34 per common share).
- Received Toronto Stock Exchange ("TSX") approval for Headwater's Normal Course Issuer Bid ("NCIB") application to purchase for cancellation up to 19,020,755 common shares during the period commencing on May 6, 2025 and ending on May 5, 2026. During the year ended December 31, 2025, Headwater repurchased approximately 1.05 million common shares for cancellation at an average price of \$7.30 per common share for total proceeds of \$7.7 million.

- (1) Capital management measure that does not have any standardized meaning under IFRS and therefore may not be comparable with the calculation. Refer to "Management of capital" in note 16 of the audited annual financial statements and to "Non-GAAP and Other Financial Measures" within this MD&A.
- (2) Non-GAAP ratio that does not have any standardized meaning under IFRS and therefore may not be comparable with the calculation of similar measures of other entities. Refer to "Non-GAAP and Other Financial Measures" within this MD&A.
- (3) Non-GAAP financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable with the calculation of similar measures of other entities. Refer to "Non-GAAP and Other Financial Measures" within this MD&A.

Results of Operations

Production and Pricing

	Three months ended		Percent Change	Year ended		Percent Change
	December 31, 2025	2024		December 31, 2025	2024	
Average daily production						
Heavy oil (bbls/d)	22,091	20,304	9	20,707	19,095	8
Natural gas (mmcf/d)	12.1	7.2	68	11.5	6.9	67
Natural gas liquids (bbls/d)	143	51	180	160	67	139
Barrels of oil equivalent (boe/d)	24,259	21,559	13	22,776	20,310	12
Average daily sales (boe/d) ⁽¹⁾						
Heavy oil (bbls/d)	21,998	20,288	8	20,689	19,060	9
Natural gas (mmcf/d)	12.1	7.2	68	11.5	6.9	67
Natural gas liquids (bbls/d)	143	51	180	160	67	139
Barrels of oil equivalent (boe/d)	24,166	21,543	12	22,758	20,275	12
Headwater average sales price ⁽²⁾						
Heavy oil (\$/bbl) ⁽³⁾	66.34	80.26	(17)	74.32	82.71	(10)
Natural gas (\$/mcf)	8.82	8.91	(1)	6.43	4.87	32
Natural gas liquids (\$/bbl)	64.29	77.84	(17)	71.53	79.86	(10)
Barrels of oil equivalent (\$/boe)	65.20	78.76	(17)	71.30	79.67	(11)
Average Benchmark Price						
WTI (US\$/bbl) ⁽⁴⁾	59.14	70.27	(16)	64.81	75.72	(14)
WCS differential to WTI (US\$/bbl)	(11.20)	(12.55)	(11)	(11.13)	(14.75)	(25)
WCS (Cdn\$/bbl) ⁽⁵⁾	66.89	80.75	(17)	75.06	83.53	(10)
Condensate at Edmonton (Cdn\$/bbl)	79.16	98.25	(19)	88.16	99.24	(11)
AGT (US\$/mmbtu) ⁽⁶⁾	14.96	9.13	64	10.75	4.71	128
AECO 5A (Cdn\$/GJ)	2.11	1.40	51	1.59	1.38	15
NYMEX Henry Hub (US\$/mmbtu)	3.55	2.79	27	3.43	2.27	51
Exchange rate (Cdn\$ to US\$)	0.72	0.71	1	0.72	0.73	(1)

(1) Includes sales of heavy crude oil excluding the impact of purchased condensate and butane. The Company's heavy oil sales volumes and production volumes differ due to changes in inventory.

(2) Average sales prices are calculated using average sales volumes.

(3) Realized heavy oil prices are based on sales, net of blending expense.

(4) WTI = West Texas Intermediate

(5) WCS = Western Canadian Select

(6) AGT = Algonquin city-gates daily. The AGT price is the average for the winter producing months in the McCully field which include January – April and December.

Sales

	Three months ended		Percent Change	Year ended		Percent Change
	December 31, 2025	2024		December 31, 2025	2024	
	<i>(thousands of dollars)</i>			<i>(thousands of dollars)</i>		
Heavy oil	140,033	156,442	(10)	585,695	604,153	(3)
Blending expense	(5,772)	(6,632)	(13)	(24,465)	(27,166)	(10)
Heavy oil, net of blending expense ⁽¹⁾	134,261	149,810	(10)	561,230	576,987	(3)
Natural gas	9,856	5,921	66	26,881	12,285	119
Natural gas liquids	848	368	130	4,174	1,959	113
Gathering, processing and transportation	343	376	(9)	1,530	1,407	9
Total sales, net of blending expense ⁽¹⁾	145,308	156,475	(7)	593,815	592,638	-

(1) Non-GAAP financial measure. Refer to "Non-GAAP and Other Financial Measures" within this MD&A.

Heavy Oil – Alberta

The Company's realized price received for its heavy crude oil is determined by the quality of crude compared to the benchmark price of WCS. Headwater's heavy crude oil production (average 18 – 22° API) is blended with diluent in order to meet pipeline transportation specifications.

WTI pricing has weakened year over year, due to softer supply and demand fundamentals driven by global recession fears following ongoing changes to U.S. foreign trade policies, along with increased OPEC+ output. Offsetting the impact of lower WTI pricing was the narrowing of the WCS differential to WTI due to lower Western Canadian heavy oil inventories and a weaker Canadian dollar. Headwater's discount to WCS narrowed during the year ended December 31, 2025, compared to the prior year, primarily due to blending optimization and stronger realized pricing relative to WCS, while Headwater's discount to WCS remained consistent for the three months ended December 31, 2025, compared to the corresponding period of the prior year.

During the three months ended December 31, 2025, Headwater's heavy oil sales, net of blending expense, decreased to \$134.3 million from \$149.8 million in the corresponding period of the prior year. This decrease was attributable to a 17% decrease in realized heavy oil commodity pricing, partially offset by an 8% increase in heavy oil sales volumes. During the year ended December 31, 2025, Headwater's heavy oil sales, net of blending expense, decreased to \$561.2 million from \$577.0 million in the prior year. This decrease was attributable to a 10% decrease in realized heavy oil commodity pricing, partially offset by a 9% increase in heavy oil sales volumes. This decrease in realized heavy oil commodity pricing for both the three months and year ended December 31, 2025, is consistent with the decrease in benchmark WCS pricing.

During the three months and year ended December 31, 2025, Headwater's heavy oil sales volumes averaged 21,998 bbls/d and 20,689 bbls/d, respectively, compared to 20,288 bbls/d and 19,060 bbls/d in the corresponding periods of 2024. The Company's heavy oil sales volumes have increased as a result of Headwater's growth-oriented drilling programs, along with successful secondary recovery efforts reducing corporate oil production declines. Headwater drilled 61.0 total net crude oil wells during the year ended December 31, 2025, and drilled 76.0 total net crude oil wells during the year ended December 31, 2024, increasing the Company's heavy oil production.

Natural Gas – New Brunswick and Alberta

The Company produces natural gas out of the McCully field in New Brunswick. The transaction price is based on the AGT daily benchmark price adjusted for a premium contract adder. Consistent with prior years, the Company shut-in McCully natural gas production for the summer season effective May 1, 2025, and resumed operations December 1, 2025, to take advantage of the AGT market's premium winter pricing. Headwater also produces natural gas in Alberta. In December 2024, a third-party gathering system in Marten Hills West was commissioned, increasing the Company's sales volumes out of the Marten Hills area. The natural gas sales transaction price is based on the AECO 5A daily benchmark price adjusted for delivery location and heat content.

For both the three months and year ended December 31, 2025, natural gas sales increased to \$9.9 million and \$26.9 million, respectively, from \$5.9 million and \$12.3 million in the corresponding periods of the prior year, driven by an increase in both McCully and Alberta natural gas sales over the periods. AGT benchmark pricing increased significantly in 2025, driven by cooler U.S. winter temperatures and declining natural gas storage levels in the northeastern U.S. While AECO prices continue to be depressed as a result of sustained high natural gas storage levels in Western Canada, natural gas sales out of Marten Hills increased, primarily as a result of increased natural gas sales volumes in the area.

During the three months and year ended December 31, 2025, Headwater's natural gas sales volumes increased to 12.1 mmcf/d and 11.5 mmcf/d, respectively, from 7.2 mmcf/d and 6.9 mmcf/d in the corresponding periods of the prior year, primarily as a result of incremental sales volumes in Alberta, from the newly constructed third-party gathering system in Marten Hills West.

Financial Derivatives Gains and Losses

	Three months ended		Percent Change	Year ended		Percent Change
	December 31, 2025	2024		December 31, 2025	2024	
	<i>(thousands of dollars)</i>			<i>(thousands of dollars)</i>		
Realized gains (losses)	(2,484)	(688)	261	(6,506)	4,982	(231)
Unrealized gains (losses)	894	(84)	(1164)	(691)	(3,803)	(82)
Financial derivative gains (losses)	<u>(1,590)</u>	<u>(772)</u>	106	<u>(7,197)</u>	<u>1,179</u>	(710)
Per boe	(0.72)	(0.39)	85	(0.87)	0.16	(644)

Natural gas and crude oil commodity contracts

Headwater enters into financial derivative commodity contracts to manage the risks associated with fluctuations in commodity prices.

The realized financial derivative losses of \$2.5 million recognized during the three months ended December 31, 2025, primarily represent the Company's crude oil contracts referenced to the WCS differential to WTI and the Company's McCully natural gas contracts referenced to the AGT price. Headwater recognized \$1.9 million of losses on its WCS differential contracts during the three months ended December 31, 2025, as the commodity contracts to fix the WCS to WTI differential averaged US\$13.32/bbl, compared to the average settlement differential of US\$11.20/bbl. The settlement differential narrowed due to lower average Western Canadian heavy oil inventory balances during the quarter. The Company recognized \$0.7 million of losses on its AGT contracts during the three months ended December 31, 2025, as the commodity contracts to fix the AGT price averaged Cdn\$18.36/mmbtu, compared to the average settlement price of Cdn\$20.64/mmbtu. The AGT settlement price was higher than expected due to cooler U.S. winter temperatures and declining natural gas storage levels in the northeastern U.S. These realized losses were partially offset by realized gains of \$0.1 million on the Company's AECO 5A contracts.

The realized financial derivative losses of \$6.5 million recognized during the year ended December 31, 2025, primarily relate to losses on both the Company's WCS differential and AGT fixed price contracts. Headwater's WCS differential and AGT fixed price contracts generated total realized losses of \$4.4 million and \$3.8 million, respectively, for the year ended December 31, 2025. These realized losses were partially offset by realized gains of \$1.7 million on the Company's AECO 5A contracts, as the commodity contracts to fix the AECO 5A price averaged Cdn\$2.34/GJ for the year ended December 31, 2025, compared to the average settlement price of Cdn\$2.11/GJ. Settlement pricing for AECO 5A continues to be depressed, due to sustained high natural gas storage levels in Western Canada.

The unrealized gains (losses) recorded are a result of the change in fair value of the Company's outstanding financial derivative commodity contracts over the periods. As at December 31, 2025, the fair value of Headwater's outstanding financial derivative commodity contracts was a net unrealized liability of \$832 thousand as reflected in the audited financial statements. The fair value or mark to market value of these contracts is based upon the estimated amount that would have been receivable/payable as at December 31, 2025, had the contracts been monetized or terminated. Subsequent changes in the fair value of the contracts are recognized in each reporting period and could be materially different than what is recorded as at December 31, 2025. For the three months and year ended December 31, 2025, Headwater recognized unrealized gains of \$894 thousand and unrealized losses of \$691 thousand, respectively, compared to unrealized losses of \$84 thousand and \$3.8 million in the corresponding periods of 2024.

As at December 31, 2025, Headwater had the following financial derivative commodity contracts outstanding:

Commodity	Index	Type	Term	Daily Volume	Contract Price
Natural Gas	AGT	Fixed	Jan 2026	7,000 mmbtu	Cdn\$15.23/mmbtu
Natural Gas	AGT	Fixed	Feb 2026	6,000 mmbtu	Cdn\$14.99/mmbtu
Natural Gas	AGT	Fixed	Mar 2026	4,500 mmbtu	Cdn\$13.91/mmbtu
Natural Gas	AGT	Fixed	Apr 2026	5,000 mmbtu	Cdn\$5.31/mmbtu
Crude Oil	WCS Basis	Differential	Jan 2026 - Dec 2026	2,000 bbl	US\$13.00/bbl
Natural Gas	AECO 5A	Fixed	Apr 2026 - Oct 2026	2,000 GJ	Cdn\$2.93/GJ

Subsequent to December 31, 2025, the Company entered into additional financial derivative commodity contracts. Refer to the heading "Subsequent Events".

Foreign exchange contracts

As of April 1, 2024, all of Headwater's revenue contracts are settled in Canadian dollars. However, the Company is exposed to fluctuations in the Canadian to U.S. dollar exchange rate given realized pricing is directly influenced by U.S. dollar denominated benchmark pricing and from exposure to its U.S. dollar denominated WCS commodity contracts. Headwater may decide to mitigate a portion of this risk by periodically entering into foreign exchange contracts. As at December 31, 2025, Headwater did not have any foreign exchange contracts outstanding.

Royalty Expense

	Three months ended		Percent Change	Year ended		Percent Change
	December 31, 2025	December 31, 2024		December 31, 2025	December 31, 2024	
	<i>(thousands of dollars)</i>			<i>(thousands of dollars)</i>		
Total royalty expense	22,876	27,372	(16)	103,987	108,307	(4)
Average royalty rate ⁽¹⁾	15.7%	17.5%	(10)	17.5%	18.3%	(4)
Per boe (\$)	10.29	13.81	(25)	12.52	14.60	(14)

(1) Non-GAAP ratio. Refer to the advisory "Non-GAAP and Other Financial Measures".

Royalty expense primarily consists of crown royalties payable to the Alberta and New Brunswick provincial governments and the gross overriding royalty ("GORR") payable to Topaz Energy Corp. The GORR is associated with production out of the Company's Marten Hills assets.

Under the Alberta Modernized Royalty Framework, the Company pays a flat royalty of 5% on a well's production until the well's total revenue exceeds the drilling and completion cost allowance, then royalty rates increase on a sliding scale up to 40% depending on reference commodity pricing.

For the three months ended December 31, 2025, royalty expense decreased to \$22.9 million from \$27.4 million in the corresponding period of 2024, primarily due to a decrease in the average royalty rate to 15.7% from 17.5%, attributable to a drop in the Government of Alberta's published par price over the period. For the year ended December 31, 2025, royalty expense decreased to \$104.0 million from \$108.3 million in 2024, primarily due to a decrease in the average royalty rate to 17.5% from 18.3%, attributable to a drop in the Government of Alberta's published par price over the year.

Transportation Expense

	Three months ended December 31,		Percent Change	Year ended December 31,		Percent Change
	2025	2024		2025	2024	
	<i>(thousands of dollars)</i>			<i>(thousands of dollars)</i>		
Transportation expense	12,439	10,429	19	46,393	40,897	13
Per boe (\$)	5.59	5.26	6	5.59	5.51	1

Transportation expense includes clean oil trucking, terminal fees and pipeline tariffs incurred to move heavy crude oil production to the sales point.

For the three months and year ended December 31, 2025, transportation expense increased to \$12.4 million and \$46.4 million, respectively, from \$10.4 million and \$40.9 million in the corresponding periods of the prior year due to an increase in heavy oil sales volumes.

For the three months ended December 31, 2025, transportation expense per boe increased to \$5.59 from \$5.26 in the corresponding period of the prior year, due to higher trucking costs. Transportation expense per boe for the year ended December 31, 2025, was comparable to the prior year.

Headwater has firm transportation service commitments in place to secure pipeline capacity to the point of sale. Refer to “Contractual Obligations and Commitments” for more information.

Production Expense

	Three months ended December 31,		Percent Change	Year ended December 31,		Percent Change
	2025	2024		2025	2024	
	<i>(thousands of dollars)</i>			<i>(thousands of dollars)</i>		
Production expense	16,019	15,133	6	61,349	54,551	12
Per boe (\$)	7.21	7.64	(6)	7.39	7.35	1

For the three months and year ended December 31, 2025, production expense increased to \$16.0 million and \$61.3 million, respectively, from \$15.1 million and \$54.6 million in the corresponding periods of the prior year due to an increase in production volumes.

For the three months ended December 31, 2025, production expense per boe decreased to \$7.21 from \$7.64 in the corresponding period of the prior year, due to lower maintenance costs driven by favorable winter conditions. Production expense per boe for the year ended December 31, 2025, was comparable to the prior year.

Netbacks

Operating netback reflects the Company’s margin on a per-barrel of oil equivalent basis. The following table provides a reconciliation of Headwater’s operating netback and operating netback, including financial derivatives. Refer to the heading “Non-GAAP and Other Financial Measures” for more information.

	Three months ended December 31,		Percent Change	Year ended December 31,		Percent Change
	2025	2024		2025	2024	
	<i>(\$/boe)</i>			<i>(\$/boe)</i>		
Sales	67.95	82.30	(17)	74.44	83.52	(11)
Royalties	(10.29)	(13.81)	(25)	(12.52)	(14.60)	(14)
Transportation and blending	(8.19)	(8.61)	(5)	(8.53)	(9.17)	(7)
Production expense	(7.21)	(7.64)	(6)	(7.39)	(7.35)	1
Operating netback ⁽¹⁾	42.26	52.24	(19)	46.00	52.40	(12)
Realized gains (losses) on financial derivatives	(1.12)	(0.35)	220	(0.78)	0.67	(216)
Operating netback, including financial derivatives ⁽¹⁾	41.14	51.89	(21)	45.22	53.07	(15)

(1) Non-GAAP ratio. Refer to the advisory “Non-GAAP and Other Financial Measures”.

For the three months and year ended December 31, 2025, the Company recorded an operating netback, including financial derivatives of \$41.14 per boe and \$45.22 per boe, respectively, compared to \$51.89 per boe and \$53.07 per boe in the corresponding periods of the prior year. Lower operating netback, including financial derivatives in both periods is due to lower realized heavy oil pricing, consistent with decreased benchmark WCS pricing, and higher realized financial derivative losses, primarily due to losses on both the Company’s WCS differential and AGT fixed price contracts, partially offset by lower royalties driven by lower par pricing.

General and Administrative (“G&A”) Expenses

	Three months ended December 31,		Percent Change	Year ended December 31,		Percent Change
	2025	2024		2025	2024	
	<i>(thousands of dollars)</i>			<i>(thousands of dollars)</i>		
Gross G&A expenses	5,073	4,334	17	17,269	15,396	12
Capitalized G&A	(1,576)	(1,302)	21	(4,873)	(4,404)	11
Net G&A expenses	3,497	3,032	15	12,396	10,992	13
Per boe (\$)	1.57	1.53	3	1.49	1.48	1

For the three months and year ended December 31, 2025, net G&A expenses increased to \$3.5 million and \$12.4 million, respectively, from \$3.0 million and \$11.0 million in the corresponding periods of 2024. Increased net G&A expenses on an absolute basis were mainly a result of increased employee related costs and professional fees due to the growth experienced by the Company over the periods. G&A expenses per boe were consistent over the periods.

Interest Income and Other Expense

	Three months ended		Percent Change	Year ended		Percent Change
	December 31,			December 31,		
	2025	2024		2025	2024	
	<i>(thousands of dollars)</i>			<i>(thousands of dollars)</i>		
Interest income	669	1,198	(44)	3,596	5,705	(37)
Foreign exchange gains	13	3	333	10	36	(72)
Accretion on decommissioning liability	(388)	(393)	(1)	(1,687)	(1,445)	17
Interest on repayable contribution	(218)	(229)	(5)	(886)	(884)	-
Interest on lease liability	(45)	(55)	(18)	(196)	(106)	85
Total interest income and other expense	<u>31</u>	<u>524</u>	(94)	<u>837</u>	<u>3,306</u>	(75)
Per boe (\$)	0.01	0.27	(96)	0.10	0.45	(78)

For the three months and year ended December 31, 2025, interest income and other expense decreased to \$31 thousand and \$837 thousand, respectively, from \$524 thousand and \$3.3 million in the corresponding periods of 2024 primarily due to lower interest income. The decrease in interest income for the three months and year ended December 31, 2025, is a result of carrying a lower average cash balance, when compared to the same periods in 2024, coupled with a decrease in the average interest rate earned over the periods driven by a series of prime rate cuts in late 2024 and into 2025.

Stock-based Compensation

	Three months ended		Percent Change	Year ended		Percent Change
	December 31,			December 31,		
	2025	2024		2025	2024	
	<i>(thousands of dollars)</i>			<i>(thousands of dollars)</i>		
Stock options	-	4	(100)	-	201	(100)
Deferred share units ("DSUs")	953	233	309	2,563	1,138	125
Share awards	15,359	7,271	111	29,422	13,888	112
Capitalized stock-based compensation	(3,294)	(1,822)	81	(5,974)	(3,223)	85
Stock-based compensation expense	<u>13,018</u>	<u>5,686</u>	129	<u>26,011</u>	<u>12,004</u>	117
Per boe (\$)	5.86	2.87	104	3.13	1.62	93

During the three months and year ended December 31, 2025, stock-based compensation expense increased to \$13.0 million and \$26.0 million, respectively, from \$5.7 million and \$12.0 million in the corresponding periods of the prior year, primarily due to the recognition of an estimated performance multiplier for the performance share units ("PSUs") granted in 2023, which vest in 2026, as well as incremental expense for the increase in Headwater's share price from \$6.61 at December 31, 2024 to \$9.37 at December 31, 2025, representing a 42% increase. The expense for stock options was \$nil for the relevant periods in 2025, due to all outstanding stock options being fully vested.

Share Awards (Cash-Settled)

The Company has an incentive awards plan (the "Award Plan") that provides for the grant of restricted share units ("RSUs") and PSUs to officers, employees and consultants of the Company. Under the Award Plan, the aggregate number of common shares reserved for issuance may not exceed 4.5% of the aggregate number of issued and outstanding common shares. Generally, one third of the RSUs will vest on each of the first, second and third anniversaries of the date of grant and all PSUs will vest on the third anniversary of the date of grant, unless otherwise determined by the Board of Directors of the Company (the "Board"). For PSUs, the amount of stock-based compensation payable and related expense is adjusted based on a performance multiplier ranging from 0 to 2 times, which is based on certain corporate performance measures, as determined by the Board.

During the fourth quarter of 2024, the Board approved the cash settlement of the Company's outstanding PSUs. Previously, PSUs had been accounted for as equity-settled. As a result of this modification to the Company's outstanding PSUs from equity-settled to cash-settled, the fair value of the PSUs previously expensed was reclassified from contributed surplus to stock-based compensation payable. Subsequent to this modification, the grant date fair value is used to record the cost of the PSUs and any subsequent remeasurement of the liability is also recognized in the Statements of Income and Comprehensive Income. All RSUs are also cash settled.

As at December 31, 2025, there were 443 thousand RSUs outstanding and 3,729 thousand PSUs outstanding.

DSUs (Cash-Settled)

The Company also has a DSU plan ("the DSU Plan") that provides for grants of DSUs to non-management directors. Each DSU vests on the date of grant; however, settlement of the DSU occurs when the individual ceases to be a director of the Company. DSUs are to be settled in cash or by payment in common shares acquired through the facilities of the Toronto Stock Exchange ("TSX"). It is the intention of the Company to settle the DSUs in cash. The directors may also elect to receive all of their annual cash compensation in the form of DSUs provided that such election must be made on December 1st of the preceding calendar year (or within a certain prescribed time frame if an individual becomes a director after the commencement of a calendar year or after the initial adoption of the DSU Plan) and after such date the election will be irrevocable for such year. DSUs are measured at fair value using the Company's closing share price on December 31, 2025.

As at December 31, 2025, there were 409 thousand DSUs outstanding.

Stock Options

As at December 31, 2025, there were nil stock options outstanding. The Company did not grant any stock options in 2025, 2024 or 2023 and does not intend to grant any further options under the Company's stock option plans.

Depletion & Depreciation

	Three months ended		Percent Change	Year ended		Percent Change
	December 31, 2025	December 31, 2024		December 31, 2025	December 31, 2024	
	<i>(thousands of dollars)</i>			<i>(thousands of dollars)</i>		
Depletion & depreciation	29,438	31,382	(6)	127,037	124,883	2
Per boe (\$)	13.24	15.83	(16)	15.29	16.83	(9)

Depletion expense is calculated using the unit-of-production method which is based on production volumes in relation to the proved plus probable reserves base.

For the three months ended December 31, 2025, depletion and depreciation expense decreased to \$29.4 million, from \$31.4 million in the corresponding period of the prior year, as a result of a decrease in the depletion and depreciation rate, which more than offset the increase in production volumes over the period. For the year ended December 31, 2025, depletion and depreciation expense increased to \$127.0 million from \$124.9 million in the prior year, as a result of an increase in production volumes.

For the three months and year ended December 31, 2025, Headwater's depletion and depreciation rate decreased to \$13.24 per boe and \$15.29 per boe, respectively, from \$15.83 per boe and \$16.83 per boe in the corresponding periods of the prior year, due to significant reserve additions recorded in the 2025 year-end reserves report, resulting from successful drilling and waterflood results.

Exploration and Evaluation (“E&E”) Expense

	Three months ended December 31,		Percent Change	Year ended December 31,		Percent Change
	2025	2024		2025	2024	
	<i>(thousands of dollars)</i>			<i>(thousands of dollars)</i>		
E&E expense	8,256	-	100	8,256	-	100
Per boe (\$)	3.71	-	100	0.99	-	100

During the year ended December 31, 2025, the company recognized \$8.3 million of E&E expense related to its Saskatchewan assets.

Impairment Assessment

As at December 31, 2025 and 2024, there were no indicators of impairment identified for the Company’s property, plant and equipment (“PP&E”) assets. As such, an impairment test was not performed.

Current and Deferred Income Taxes

	Three months ended December 31,		Percent Change	Year ended December 31,		Percent Change
	2025	2024		2025	2024	
	<i>(thousands of dollars)</i>			<i>(thousands of dollars)</i>		
Current income tax expense	9,176	13,114	(30)	40,220	51,962	(23)
Deferred income tax expense (recovery)	(281)	1,172	(124)	8,599	5,499	56
Total income tax expense	<u>8,895</u>	<u>14,286</u>	(38)	<u>48,819</u>	<u>57,461</u>	(15)
Canadian statutory income tax rate	23.2%	23.2%	-	23.2%	23.2%	-
Effective income tax rate ⁽¹⁾	10.4%	13.0%	(20)	11.0%	13.4%	(18)
Current income tax per boe (\$)	4.13	6.62	(38)	4.84	7.00	(31)
Deferred income tax per boe (\$)	(0.13)	0.59	(122)	1.04	0.74	41
Total income tax per boe (\$)	4.00	7.21	(45)	5.88	7.74	(24)

(1) Non-GAAP ratio. Refer to the advisory “Non-GAAP and Other Financial Measures”.

For the three months and year ended December 31, 2025, current income tax expense decreased to \$9.2 million and \$40.2 million, respectively, from \$13.1 million and \$52.0 million in the corresponding periods of the prior year, due to lower taxable income as a result of lower pre-tax adjusted funds flow from operations, primarily driven by lower realized heavy oil pricing. The Company’s statutory income tax rate was consistent over the periods at 23.2%.

At December 31, 2025, the Company had approximately \$471.4 million of tax pools available to be applied against future taxable income. The Canadian federal tax pools are estimated as follows:

<i>(thousands of dollars)</i>	Estimated balance at December 31, 2025
Canadian oil and gas property expense	118,209
Canadian development expense	259,242
Undepreciated capital cost	93,912
Share issue costs	24
Total	471,387

Cash Flows Provided by Operating Activities and Adjusted Funds Flow from Operations

Refer to the heading “Non-GAAP and Other Financial Measures” for more information.

	Three months ended December 31,		Percent Change	Year ended, December 31,		Percent Change
	2025	2024		2025	2024	
	<i>(thousands of dollars)</i>			<i>(thousands of dollars)</i>		
Cash flows provided by operating activities	72,668	76,016	(4)	297,137	316,737	(6)
Changes in non-cash working capital	7,376	14,774	(50)	13,205	12,096	9
Current income tax expense	(9,176)	(13,114)	(30)	(40,220)	(51,962)	(23)
Income taxes paid	8,386	10,227	(18)	54,103	59,686	(9)
Restricted cash	-	-	-	2,000	-	100
Adjusted funds flow from operations ⁽¹⁾	<u>79,254</u>	<u>87,903</u>	<u>(10)</u>	<u>326,225</u>	<u>336,557</u>	<u>(3)</u>

	Three months ended December 31,		Percent Change	Year ended, December 31,		Percent Change
	2025	2024		2025	2024	
	<i>(\$/boe)</i>			<i>(\$/boe)</i>		
Cash flows provided by operating activities	32.69	38.35	(15)	35.77	42.68	(16)
Changes in non-cash working capital	3.32	7.45	(55)	1.59	1.63	(2)
Current income tax expense	(4.13)	(6.62)	(38)	(4.84)	(7.00)	(31)
Income taxes paid	3.77	5.16	(27)	6.51	8.04	(19)
Restricted cash	-	-	-	0.24	-	100
Adjusted funds flow netback ⁽²⁾	<u>35.65</u>	<u>44.34</u>	<u>(20)</u>	<u>39.27</u>	<u>45.35</u>	<u>(13)</u>

- (1) Capital management measure. Refer to “Management of capital” in note 16 of the audited annual financial statements and to “Non-GAAP and Other Financial Measures” within this MD&A.
- (2) Non-GAAP ratio. Refer to the advisory “Non-GAAP and Other Financial Measures”.

For the three months and year ended December 31, 2025, adjusted funds flow from operations decreased to \$79.3 million and \$326.2 million, respectively, from \$87.9 million and \$336.6 million in the corresponding periods of the prior year, due to a lower adjusted funds flow netback, partially offset by a 12% increase in sales volumes in both periods. For the three months and year ended December 31, 2025, the Company recorded an adjusted funds flow netback of \$35.65 per boe and \$39.27 per boe, respectively, compared to \$44.34 per boe and \$45.35 per boe in the corresponding periods of the prior year. Lower adjusted funds flow netback in both periods is a result of a lower operating netback, including financial derivatives primarily due to a decline in realized heavy oil pricing, partially offset by lower current income taxes.

Capital Expenditures

	Three months ended		Percent Change	Year ended		Percent Change
	December 31, 2025	December 31, 2024		December 31, 2025	December 31, 2024	
	<i>(thousands of dollars)</i>			<i>(thousands of dollars)</i>		
Land and geological & geophysical	7,711	7,719	-	30,238	28,753	5
Site preparation	7,080	5,299	34	22,974	27,226	(16)
Drilling and completions	24,882	27,322	(9)	138,144	132,384	4
Equipping and facilities	6,384	8,345	(23)	36,896	34,467	7
Corporate	9	1	800	36	36	-
Capital expenditures ⁽¹⁾	46,066	48,686	(5)	228,288	222,866	2
Acquisition (non-cash consideration) ⁽²⁾	-	-	-	7,740	-	100
Capital expenditures including acquisition ⁽¹⁾	46,066	48,686	(5)	236,028	222,866	6

(1) Non-GAAP financial measure. Refer to "Non-GAAP and Other Financial Measures" within this MD&A.

(2) Includes share consideration of \$7.7 million for the issuance of 1,000,000 common shares by Headwater as consideration for the acquisition of certain E&E assets in the Greater Pelican area which closed on September 25, 2025. The fair value was determined using Headwater's closing share price on the closing date.

During the three months ended December 31, 2025, the Company invested a total of \$46.1 million on capital expenditures including \$24.9 million on drilling and completions, \$7.7 million on land and geological & geophysical, \$7.1 million on site preparation, including road construction and \$6.4 million on equipping and facilities.

During the year ended December 31, 2025, the Company invested a total of \$228.3 million on capital expenditures including \$138.1 million on drilling and completions, \$36.9 million on equipping and facilities, \$30.2 million on land and geological & geophysical and \$23.0 million on site preparation, including road construction.

Drilling Activity

The following table summarizes the Company's drilling results:

	Three months ended December 31,				Year ended December 31,			
	2025		2024		2025		2024	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Crude oil ⁽¹⁾	11	11.0	8	8.0	62	61.0	76	76.0
Natural gas	-	-	-	-	-	-	-	-
Injection	14	14.0	13	13.0	38	38.0	19	19.0
Source/stratigraphic test	1	1.0	1	1.0	6	6.0	4	4.0
Total	26	26.0	22	22.0	106	105.0	99	99.0
Success	100%	100%	100%	100%	100%	100%	100%	100%

(1) Four of the previously classified stratigraphic test wells have been reclassified to crude oil wells given they were re-entered during the year ended December 31, 2025.

Decommissioning Liabilities

As at December 31, 2025, Headwater's decommissioning liabilities were \$35.2 million, representing a decrease of \$13.4 million from the Company's decommissioning liabilities of \$48.6 million as at December 31, 2024. This decrease of \$13.4 million is attributed to a downward change in estimate of \$23.6 million and settlements of \$0.3 million, partially offset by additions of \$8.8 million and accretion of \$1.7 million. The \$23.6 million downward change in estimate is a combination of a \$12.9 million downward revision due to change in cost estimates underpinned by a decrease to the industry's abandonment cost benchmarks, a

\$6.2 million downward revision relates to changes in time to abandonment, a \$6.5 million downward revision is a result of an increase in risk-free rate over the year from 3.3% at December 31, 2024 to 3.9% at December 31, 2025 and a \$2.0 million upward revision is a result of an increase in the inflation rate over the year from 1.8% at December 31, 2024 to 2.0% at December 31, 2025. The total undiscounted uninflated amount of estimated cash flows required to settle these obligations is \$69.9 million (December 31, 2024 - \$76.1 million).

2025 Guidance

A summary of the guidance that was provided by the Company on September 8, 2025, compared to actual results from 2025 are as follows:

	2025 Guidance	2025 Actuals
2025 annual production (boe/d) ⁽¹⁾	22,600	22,776
Adjusted funds flow from operations ⁽²⁾	\$320 million	\$326 million
Capital expenditures ⁽³⁾	\$225 million	\$228 million
Adjusted working capital ⁽²⁾	\$45 million	\$24 million
Dividends ⁽⁴⁾	\$0.11/common share	\$0.11/common share

- (1) Refer to "Results of Operations – Production and Pricing" within this MD&A for a breakdown of 2025 annual and fourth quarter production by product type.
- (2) Capital management measure. Refer to "Management of capital" in note 16 of the audited annual financial statements and to "Non-GAAP and Other Financial Measures" within this MD&A.
- (3) Non-GAAP financial measure. Refer to "Non-GAAP and Other Financial Measures" within this MD&A.
- (4) Refer to "Dividend Policy" within this MD&A.

Adjusted working capital is \$21 million lower than 2025 guidance as a result of a \$16 million increase to the Company's estimated stock-based compensation payable as a result of an increase to the estimated PSU multiplier, as well as a significant increase to Headwater's closing share to \$9.37 at December 31, 2025. Additionally, the Company's purchase of approximately 1.05 million shares for cancellation for total proceeds of \$7.7 million pursuant to the NCIB and higher capital expenditures of \$3 million also contributed to lower adjusted working capital. These decreases were slightly offset by higher adjusted funds flow from operations of \$6 million, primarily attributed to higher realized commodity pricing when compared to forecasted prices in the fourth quarter of 2025.

2026 Guidance

Headwater is reconfirming its 2026 guidance released on December 3, 2025. Headwater expects to fund capital expenditures through existing working capital and forecasted cash flows from operating activities.

	2026 Guidance December 3, 2025
Average Daily Production	
Annual (boe/d)	24,500
Pricing	
Crude oil - WTI (US\$/bbl)	60.00
Crude oil - WCS (Cdn\$/bbl)	67.00
Exchange rate (Cdn\$ to US\$)	0.72
Natural gas - AGT (US\$/mmbtu)	10.60
Financial Summary (\$millions)	
Estimated capital expenditures ⁽¹⁾	185
Estimated adjusted funds flow from operations ⁽²⁾	300
Dividends ⁽³⁾	\$0.11/common share

- (1) Non-GAAP financial measure. Refer to "Non-GAAP and Other Financial Measures" within this MD&A.
- (2) Capital management measure. Refer to "Management of capital" in note 16 of the audited annual financial statements and to "Non-GAAP and Other Financial Measures" within this MD&A.
- (3) Refer to "Dividend Policy" within this MD&A.
- (4) For assumptions utilized in respect of the above guidance, see "Forward Looking Information" within this MD&A. Headwater expects to fund its 2026 capital expenditure budget through existing working capital and forecasted cash flows from operating activities.

Liquidity and Capital Resources

The Company's objectives when managing capital are to i) deploy capital to provide an appropriate return on investment to its shareholders; ii) maintain financial flexibility in order to preserve the Company's ability to meet financial obligations; and iii) maintain a capital structure that provides financial flexibility to execute strategic acquisitions. To aid in managing the capital structure, the Company monitors adjusted working capital and adjusted funds flow from operations.

During the year ended December 31, 2025, the Company declared \$104.7 million in quarterly cash dividends (year ended December 31, 2024 – \$95.0 million). The Company increased its quarterly cash dividend to \$0.11 per common share, from \$0.10 per common share, effective for the dividend paid on April 15, 2025 to shareholders of record at the close of business on March 31, 2025. Included in current liabilities is \$26.2 million for the dividend declared on October 29, 2025, and paid out on January 15, 2026.

On May 1, 2025, Headwater announced TSX approval of Headwater's NCIB to purchase for cancellation up to 19,020,755 common shares during the period commencing on May 6, 2025.

As at December 31, 2025, the Company had cash of \$99.7 million, adjusted working capital of \$23.6 million and no outstanding bank debt. At US \$60/bbl WTI, the Company expects to have adequate liquidity to fund its 2026 capital expenditure budget of \$185 million and quarterly cash dividends through existing working capital and forecasted adjusted funds flow from operations. Headwater anticipates that it will make use of debt or equity financing for any substantial expansion of its capital program or to finance any significant acquisitions.

To the extent that the Company's existing working capital is not sufficient to pay the cash portion of the purchase price for any future acquisition, Headwater anticipates that it will make use of additional equity or debt financings as available. Alternatively, the Company may issue equity as consideration to complete any future acquisition.

Credit Facilities

The Company has senior secured credit facilities with the National Bank of Canada and the Bank of Montreal (together, the "Lenders"). The credit facilities are comprised of extendible revolving credit facilities consisting of a \$20.0 million operating facility and an \$80.0 million syndicated facility. Headwater also has an uncommitted accordion feature that provides the Company with the ability to access an incremental \$100.0 million, subject to certain conditions, including approval from the Lenders.

As at December 31, 2025, Headwater had not drawn on the credit facility.

The credit facilities have a revolving period of 364 days, extendible annually at the request of the Company, subject to approval of the Lenders. If not extended, the credit facilities will automatically convert to a term loan and all outstanding obligations will be repayable one year after the expiry of the revolving period. The borrowing base is subject to semi-annual redeterminations occurring by May 31st and by November 30th of each year. The credit facilities are secured by a demand debenture in the amount of \$500 million. Repayments of principal are not required until the maturity date, provided that the borrowings do not exceed the authorized borrowing base and the Company is in compliance with all covenants, representations and warranties.

The credit facilities bear interest at a floating market rate with margins charged by the Lenders linked to the Company's senior debt to EBITDA ratio. EBITDA, for the purposes of calculating the senior debt to EBITDA ratio, is calculated as net income adjusted for non-cash items, interest expense and income taxes. Senior debt, for the purposes of calculating the senior debt to EBITDA ratio, is calculated as any debt of the Company excluding the financial derivative liability and repayable contribution.

The credit facilities are not subject to any financial covenants. Additionally, distributions are permitted subject to compliance with a Board approved distribution policy.

Contractual Obligations and Commitments

The following table details the undiscounted contractual maturities of the Company's financial liabilities as at December 31, 2025:

<i>(thousands of dollars)</i>	Within 1 year	1 to 5 years
Accounts payable and accrued liabilities	65,695	-
Stock-based compensation payable	28,711	11,266
Financial derivative liability	1,225	-
Current income tax liability	790	-
Dividends payable	26,154	-
Lease liability	1,104	1,457
Repayable contribution	4,675	8,076
Total	128,354	20,799

As at March 5, 2026, the Company is committed to future payments under the following agreements:

<i>(thousands of dollars)</i>	Total	2026	2027	2028	2029	2030	Thereafter
	\$	\$	\$	\$	\$	\$	\$
Transportation and operating	234,283	30,693	32,389	32,748	31,598	23,673	83,182
Lease ⁽¹⁾	1,641	448	455	463	275	-	-
Repayable contribution ⁽²⁾	12,751	4,675	8,076	-	-	-	-

(1) Relates to variable operating costs, which are a non-lease component of the Company's head office lease.

(2) Relates to scheduled undiscounted re-payments of federal government funding under the terms of the repayable contribution agreement with NRCan. See note 8.

(3) Excludes leases accounted for under IFRS 16.

Common Share Information

Share Capital

<i>(thousands)</i>	Three months ended		Year ended	
	December 31,		December 31,	
	2025	2024	2025	2024
Weighted average outstanding common shares ⁽¹⁾				
-Basic	238,142	237,512	237,877	236,386
-Diluted	240,647	237,569	239,882	236,447
Outstanding securities at December 31, 2025				
-Common shares				237,763
-Restricted share units				443
-Performance share units				3,729
-Deferred share units				409

(1) The Company uses the treasury stock method to determine the dilutive effect of stock options, RSUs and PSUs. Under this method, only "in-the-money" dilutive instruments impact the calculation of diluted income per common share. This method also assumes that the proceeds received from the exercise of all "in-the-money" dilutive instruments are used to repurchase shares at the average market price.

Changes to capital stock during the year ended December 31, 2025, were the following:

- On September 25, 2025, Headwater issued 1.0 million common shares as consideration for certain E&E assets.
- On May 1, 2025, Headwater announced that it had received TSX approval for the NCIB allowing it to purchase for cancellation up to 19,020,755 common shares during the period commencing on May 6, 2025, and terminating on the earlier of: (i) the date on which the Company has acquired all common shares sought pursuant to the NCIB; or (ii) to May 5, 2026, unless earlier terminated at the option of the Company, upon prior notice being given to the TSX. Headwater purchased approximately 1.05 million common shares for cancellation under the NCIB at an average price of \$7.30 per common share for total consideration of \$7.7 million. Total consideration includes commissions and a 2% federal tax accrued on the purchase, which is charged against capital stock.
- 177 thousand stock options were exercised for 53 thousand common shares on a cashless basis. Contributed surplus related to the options exercised of \$331 thousand was transferred to capital stock.

Changes to capital stock during the year ended December 31, 2024, were the following:

- 2.2 million stock options were exercised for 1.0 million common shares on a cashless basis, and 144 thousand stock options were exercised for 144 thousand common shares for total proceeds of \$551 thousand. Contributed surplus related to the options exercised of \$3.4 million was transferred to capital stock.

Total Market Capitalization

The Company's market capitalization at December 31, 2025 was approximately \$2.2 billion.

<i>(thousands)</i>	December 31, 2025
Common shares outstanding	237,763
Share price ⁽¹⁾	\$9.37
Total market capitalization	\$2,227,839

(1) Represents the last price traded on the TSX on December 31, 2025.

As at March 5, 2026, the Company had 237,762,877 common shares outstanding.

<i>(thousands)</i>	March 5, 2026
Outstanding securities at March 5, 2026	
-Common shares	237,763
-Restricted share units	435
-Performance share units	3,729
-Deferred share units	433

Environmental, Social and Governance Update

The following is an update on environmental, social and governance matters:

- On May 8, 2025, at the Company's annual meeting of shareholders, Cheree Stephenson was elected as a member of the Board and on July 23, 2025 Karen Nielsen was appointed as a new member of the Board. With the addition of Ms. Stephenson and Ms. Nielsen, Headwater

has achieved its Board diversification commitment to increase women representation on the Board to 30%. Currently, 33% of the directors are women.

- On December 17, 2024, a third-party natural gas gathering system in Marten Hills West was commissioned resulting in a meaningful amount of Headwater's natural gas in the area being conserved, while also significantly reducing Headwater's carbon tax obligations in the area.
- On March 21, 2024, the Board approved a new Human Rights Policy. All Headwater employees have been provided with the policy and are required to sign off on it and abide by its principles.
- Headwater has received total funding of \$17.7 million from Natural Resources Canada ("NRCan") in connection with four claim submissions to the Emissions Reduction Fund program. NRCan has provided financial assistance by way of a partially repayable interest-free loan to the Company for its working interest in the joint Marten Hills natural gas processing plant and gathering system, as well as for gas conservation equipment associated with the Company's wholly owned oil processing facility in Marten Hills (the "Project"). Headwater will repay 80% of the financial assistance pursuant to the terms and conditions of the agreement, with the remaining 20% being non-repayable. The Project is intended to partially eliminate venting and flaring of methane rich natural gas from existing and future oil wells in the Company's core area of Marten Hills. Headwater repaid 10% of the balance of \$1.4 million on June 30, 2025. The remaining repayable portion of the funds received are to be repaid as follows: 33% on June 30, 2026; and 57% on June 30, 2027.

The Board has established four committees comprised of independent members of the Board, which include the Audit Committee, Reserves Committee, Corporate Governance and Compensation Committee and Environment, Safety and Sustainability Committee. The Audit Committee and the Reserves Committee ensure the integrity of the financial and reserves reporting of the Company; the Corporate Governance and Compensation Committee is charged with independent oversight of the director nomination process, executive compensation decisions and other corporate governance matters; and the Environment, Safety and Sustainability Committee is responsible for oversight of environmental, safety and sustainability matters. For additional information relating to the governance policies and structure of the Company see the Company's management information circular dated March 25, 2025 for the annual meeting of the shareholders held on May 8, 2025, which is available on SEDAR+ at www.sedarplus.ca and the information under the heading "Corporate Responsibility" on the Company's website at www.headwaterexp.com.

Related Party Transactions

Key management personnel of the Company include its directors and senior management. In 2025, the Company recorded \$7.2 million (2024 – \$4.7 million) of wages, benefits and directors' remuneration. In 2025, stock-based compensation expense, including amounts capitalized to PP&E, relating to compensation of key management personnel was \$26.9 million (2024 – \$11.6 million).

Selected Annual Financial Information

The following table summarizes key annual financial and operating information over the most recently completed financial years.

	2025	2024	2023
<i>(thousands of dollars except share data and production volumes)</i>			
Average production volumes (boe/d) ⁽¹⁾	22,776	20,310	18,038
Average sales volumes (boe/d)	22,758	20,275	18,038
Total sales, net of blending ⁽²⁾	593,815	592,638	482,823
Net income	153,207	188,028	156,072
Net income per share			
-basic	0.64	0.80	0.66
-diluted	0.64	0.80	0.66
Cash flows provided by operating activities	297,137	316,737	303,316
Adjusted funds flow from operations ⁽³⁾	326,225	336,557	288,262
Adjusted funds flow from operations per share ⁽⁴⁾			
-basic	1.37	1.42	1.22
-diluted	1.36	1.42	1.21
Working capital	29,951	78,735	78,610
Adjusted working capital ⁽³⁾	23,581	67,578	63,526
Dividends declared	104,728	95,037	94,421
Per share	0.44	0.40	0.40
Capital expenditures ⁽²⁾	228,288	222,866	233,846
Total assets	995,167	952,636	836,335

- (1) Refer to "Results of Operations – Production and Pricing" within this MD&A for a breakdown of 2025 and 2024 annual average production by product type. 2023 average production consisted of 16,466 bbls/d of heavy oil, 8.8 mmcf/d of natural gas and 98 bbls/d of natural gas liquids.
- (2) Non-GAAP financial measure. Refer to "Non-GAAP and Other Financial Measures" within this MD&A.
- (3) Capital management measure. Refer to "Management of capital" in note 16 of the audited annual financial statements and to "Non-GAAP and Other Financial Measures" within this MD&A.
- (4) Non-GAAP ratio that does not have any standardized meaning under IFRS and therefore may not be comparable with the calculation of similar measures of other entities. Refer to "Non-GAAP and Other Financial Measures" within this MD&A.

Headwater has grown annual average production volumes significantly from 18,038 boe/d in 2023 to 22,776 boe/d in 2025, driven by significant annual capital expenditure programs, focused on delineation, development and secondary recovery implementation, which have been funded through internally generated adjusted funds flow from operations. Coinciding with this growth, the Company increased its quarterly dividend amount to \$0.11 per common share (\$0.44 per common share annualized) effective for the dividend paid on April 15, 2025. On May 1, 2025, Headwater further expanded its return of capital policy, by announcing it had received TSX approval for its NCIB allowing it to purchase for cancellation up to 19,020,755 common shares during the one-year period commencing on May 6, 2025 (unless otherwise earlier terminated in accordance with its terms). As at December 31, 2025, Headwater had repurchased approximately 1.05 million common shares for cancellation at an average price of \$7.30 per common share for total consideration of \$7.7 million.

Summary of Quarterly Information

	Q4/25	Q3/25	Q2/25	Q1/25	Q4/24	Q3/24	Q2/24	Q1/24
Financial (thousands of dollars except share data and production volumes)								
Total sales	151,080	152,101	144,944	170,155	163,107	158,382	164,281	134,034
Total sales, net of blending ⁽¹⁾⁽²⁾	145,308	146,511	138,808	163,188	156,475	151,740	157,057	127,366
Adjusted funds flow from operations ⁽³⁾	79,254	80,394	74,218	92,359	87,903	84,185	88,023	76,446
Per share - basic ⁽⁴⁾	0.33	0.34	0.31	0.39	0.37	0.35	0.37	0.32
- diluted ⁽⁴⁾	0.33	0.33	0.31	0.39	0.37	0.35	0.37	0.32
Cash flows provided by operating activities	72,668	85,861	68,673	69,935	76,016	95,272	90,402	55,047
Net income	29,311	35,869	38,023	50,004	48,907	47,634	53,868	37,619
Per share - basic	0.12	0.15	0.16	0.21	0.21	0.20	0.23	0.16
- diluted	0.12	0.15	0.16	0.21	0.21	0.20	0.22	0.16
Capital expenditures ⁽²⁾	46,066	68,671	50,704	62,847	48,686	58,196	50,717	65,267
Depletion & depreciation	29,438	32,448	32,636	32,515	31,382	32,015	30,958	30,528
Adjusted working capital ⁽³⁾	23,581	36,444	58,472	63,616	67,578	64,411	62,381	48,841
Working capital	29,951	41,767	64,836	72,107	78,735	74,925	72,404	58,336
Shareholders' equity	748,155	752,377	735,055	723,431	699,459	684,486	658,448	625,675
Dividends declared	26,154	26,264	26,155	26,155	23,776	23,767	23,765	23,729
Per share	0.11	0.11	0.11	0.11	0.10	0.10	0.10	0.10
Weighted average shares (thousands)								
Basic	238,142	237,828	237,763	237,772	237,512	237,484	237,275	235,742
Diluted ⁽⁵⁾	240,647	240,026	239,471	237,813	237,569	239,735	239,452	237,552
Shares outstanding, end of period (thousands)								
Basic	237,763	238,763	237,763	237,774	237,757	237,665	237,654	237,290
Diluted ⁽⁶⁾	237,763	238,763	237,763	237,904	237,934	241,115	241,075	241,356
Operating (6:1 boe conversion)								
Average daily production								
Heavy oil (bbls/d)	22,091	20,948	20,249	19,511	20,304	19,718	18,825	17,512
Natural gas (mmcf/d)	12.1	8.4	10.8	14.5	7.2	3.4	5.5	11.5
Natural gas liquids (bbls/d)	143	169	185	142	51	64	67	87
Barrels of oil equivalent (boe/d) ⁽⁷⁾	24,259	22,523	22,235	22,066	21,559	20,342	19,805	19,517
Average daily sales ⁽⁸⁾	24,166	22,699	22,123	22,019	21,543	20,329	19,754	19,459
Average selling prices								
Heavy oil (\$/bbl)	66.34	74.66	73.75	83.76	80.26	83.35	90.89	76.04
Natural gas (\$/mcf)	8.82	0.28	2.22	11.22	8.91	0.25	2.04	5.03
Natural gas liquids (\$/bbl)	64.29	71.28	70.38	80.82	77.84	79.95	93.25	70.69
Barrels of oil equivalent (\$/boe)	65.20	70.12	68.80	81.94	78.76	81.09	87.26	71.49
Netbacks (\$/boe)								
Operating								
Sales, net of blending	65.35	70.16	68.95	82.35	78.95	81.13	87.37	71.93
Realized gain (loss) on financial derivatives	(1.12)	(0.06)	(0.36)	(1.60)	(0.35)	0.18	(0.44)	3.45
Royalties	(10.29)	(12.74)	(12.84)	(14.47)	(13.81)	(15.74)	(16.49)	(12.34)
Transportation	(5.59)	(5.68)	(5.65)	(5.41)	(5.26)	(5.90)	(5.54)	(5.35)
Production	(7.21)	(7.01)	(7.44)	(7.93)	(7.64)	(7.46)	(7.24)	(7.04)
Operating netback, including financial derivatives (\$/boe) ⁽⁴⁾⁽⁹⁾	41.14	44.67	42.66	52.94	51.89	52.21	57.66	50.65
General and administrative	(1.57)	(1.51)	(1.44)	(1.44)	(1.53)	(1.42)	(1.50)	(1.47)
Interest income and other expense ⁽¹⁰⁾	0.31	0.40	0.45	0.59	0.60	0.76	0.81	0.95
Current income taxes	(4.13)	(5.07)	(4.81)	(5.43)	(6.62)	(6.54)	(8.01)	(6.91)
Settlement of decommissioning liability	(0.10)	-	-	(0.05)	-	-	-	(0.05)
Adjusted funds flow netback (\$/boe) ⁽⁴⁾⁽⁹⁾	35.65	38.49	36.86	46.61	44.34	45.01	48.96	43.17

- (1) Heavy oil sales are netted with blending expense to compare the realized price to benchmark. In the annual audited financial statements, blending is recorded in blending and transportation expense.
- (2) Non-GAAP financial measure. Refer to “Non-GAAP and Other Financial Measures” within this MD&A.
- (3) Capital management measure. Refer to “Management of capital” in note 16 of the annual audited financial statements and to “Non-GAAP and Other Financial Measures” within this MD&A.
- (4) Non-GAAP ratio. Refer to the advisory “Non-GAAP and Other Financial Measures”.
- (5) Diluted weighted average shares outstanding includes the impact of any stock options, RSUs and PSUs that would be outstanding as dilutive instruments using the treasury stock method. The number of outstanding RSUs and PSUs have been adjusted for dividends. As of December 31, 2025, all outstanding stock options have been exercised.
- (6) RSUs and PSUs have been excluded as the Company intends to cash settle these awards. The accounting for PSUs changed from equity to cash settlement in the fourth quarter of 2024. As of December 31, 2025, all outstanding stock options have been exercised.
- (7) See “Barrels of Oil and Cubic Feet of Natural Gas Equivalent” in this MD&A.
- (8) Includes sales of unblended heavy crude oil. The Company’s heavy oil sales volumes and production volumes differ due to changes in inventory.
- (9) Netbacks are calculated using average sales volumes. Refer to “Netbacks” in this MD&A.
- (10) Excludes unrealized foreign exchange gains/losses, accretion on decommissioning liabilities, interest on repayable contribution and interest on the lease liability.

Headwater has experienced significant quarterly growth over the past two years as a result of its significant capital expenditure programs. The Company has grown production from 19,517 boe/d in the first quarter of 2024 to a record level of 24,259 boe/d in the fourth quarter of 2025, representing a 24% increase, while maintaining a significant positive working capital balance and distributing a quarterly dividend to shareholders pursuant to the Company’s return of capital strategy. This production growth is attributed to successful drilling and secondary recovery results in the Company’s Marten Hills core and west areas, as well as discoveries in newer areas including Greater Pelican. This higher production, partially offset by lower realized heavy oil pricing in the fourth quarter of 2025, contributed to adjusted funds flow from operations of \$79.3 million, funding capital expenditures of \$46.1 million in the fourth quarter of 2025.

Off-Balance Sheet Arrangements

All off-balance sheet arrangements are in the normal course of business. Refer to the commitments under the heading “Contractual Obligations and Commitments”.

Subsequent Events

a) Dividend

Subsequent to December 31, 2025, the Company declared a cash dividend of \$0.11 per common share. The dividend will be payable on April 15, 2026, to shareholders of record at the close of business on March 31, 2026. The dividend is designated as an eligible dividend for Canadian income tax purposes.

b) Financial derivative commodity contracts:

Subsequent to December 31, 2025, Headwater entered into the following financial derivative contracts:

Commodity	Index	Type	Term	Daily Volume	Contract Price
Natural Gas	AECO 5A	Fixed	Apr 2026 - Oct 2026	1,000 GJ	Cdn\$2.26/GJ
Natural Gas	AGT	Fixed	Dec 2026 – Mar 2027	2,500 mmbtu	Cdn\$15.75/mmbtu
Crude Oil	WTI	Fixed	Mar 2026 - Dec 2026	2,500 bbl	Cdn\$95.03/bbl

Non-GAAP and Other Financial Measures

Throughout this MD&A, the Company uses various non-GAAP and other financial measures to analyze operating performance and financial position. These non-GAAP and other financial measures do not have standardized meanings prescribed under IFRS and therefore may not be comparable to similar measures presented by other entities.

Non-GAAP Financial Measures

Heavy oil sales, net of blending expense

Management utilizes heavy oil sales, net of blending expense to compare realized pricing to WCS benchmark pricing. It is calculated by deducting the Company's blending expense from heavy oil sales. In the annual financial statements blending expense is recorded within blending and transportation expense.

	Three months ended December 31,		Year ended December 31,	
	2025	2024	2025	2024
	<i>(thousands of dollars)</i>		<i>(thousands of dollars)</i>	
Heavy oil sales	140,033	156,442	585,695	604,153
Blending expense	(5,772)	(6,632)	(24,465)	(27,166)
Heavy oil sales, net of blending expense	134,261	149,810	561,230	576,987

Total sales, net of blending expense

Management utilizes total sales, net of blending expense to compare realized pricing to benchmark pricing. It is calculated by deducting the Company's blending expense from total sales. In the audited annual financial statements blending expense is recorded within blending and transportation expense.

	Three months ended December 31,		Year ended December 31,	
	2025	2024	2025	2024
	<i>(thousands of dollars)</i>		<i>(thousands of dollars)</i>	
Total sales	151,080	163,107	618,280	619,804
Blending expense	(5,772)	(6,632)	(24,465)	(27,166)
Total sales, net of blending expense	145,308	156,475	593,815	592,638

Capital expenditures

Management utilizes capital expenditures to measure total cash capital expenditures incurred in the period. Capital expenditures represents capital expenditures – E&E and capital expenditures – PP&E in the statement of cash flows in the Company's audited annual financial statements.

	Three months ended December 31,		Year ended December 31,	
	2025	2024	2025	2024
	<i>(thousands of dollars)</i>		<i>(thousands of dollars)</i>	
Cash flows used in investing activities	61,120	45,932	227,885	226,852
Proceeds from government grant	-	-	-	354
Change in non-cash working capital	(15,054)	2,754	403	(4,340)
Capital expenditures	46,066	48,686	228,288	222,866

Capital Management Measures

Adjusted Funds Flow from Operations

Management considers adjusted funds flow from operations to be a key measure to assess the Company's management of capital. Adjusted funds flow from operations is an indicator as to whether adjustments are necessary to the level of capital expenditures. For example, in periods where adjusted funds flow from operations is negatively impacted by reduced commodity pricing, capital expenditures may need to be reduced or curtailed to preserve the Company's capital structure and return of capital policy. Management believes that by excluding the impact of changes in non-cash working capital and restricted cash and adjusting for current income taxes in the period, adjusted funds flow from operations

provides a useful measure of Headwater's ability to generate the funds necessary to manage the capital needs of the Company. In addition to being a capital management measure, adjusted funds flow from operations is used by management to assess the Company's financial performance.

	Three months ended December 31,		Year ended, December 31,	
	2025	2024	2025	2024
	<i>(thousands of dollars)</i>		<i>(thousands of dollars)</i>	
Cash flows provided by operating activities	72,668	76,016	297,137	316,737
Changes in non-cash working capital	7,376	14,774	13,205	12,096
Current income tax expense	(9,176)	(13,114)	(40,220)	(51,962)
Current income taxes paid	8,386	10,227	54,103	59,686
Restricted cash	-	-	2,000	-
Adjusted funds flow from operations	79,254	87,903	326,225	336,557

Adjusted Working Capital

Adjusted working capital is a capital management measure which management uses to assess the Company's liquidity. Financial derivative receivable/liability have been excluded as these contracts are subject to a high degree of volatility prior to settlement and relate to future production periods. Financial derivative receivable/liability are included in adjusted funds flow from operations when the contracts are ultimately realized. Management has included the effects of the repayable contribution to provide a better indication of Headwater's net financing obligations.

	Year ended December 31,	
	2025	2024
	<i>(thousands of dollars)</i>	
Working capital	29,951	78,735
Repayable contribution	(7,202)	(10,916)
Financial derivative receivable	(393)	(3,088)
Financial derivative liability	1,225	2,847
Adjusted working capital	23,581	67,578

Non-GAAP Ratios

Adjusted funds flow netback, operating netback and operating netback, including financial derivatives

Adjusted funds flow netback, operating netback and operating netback, including financial derivatives are non-GAAP ratios and are used by management to better analyze the Company's performance against prior periods on a more comparable basis.

Adjusted funds flow netback is defined as adjusted funds flow from operations divided by sales volumes in the period.

Operating netback is defined as sales less royalties, transportation and blending costs and production expense divided by sales volumes in the period. Sales volumes exclude the impact of purchased condensate and butane. Operating netback, including financial derivatives is defined as operating netback including the impact of realized gains or losses on financial derivatives.

Adjusted funds flow from operations per share

Adjusted funds flow from operations per share is a non-GAAP ratio used by management to better analyze the Company's performance against prior periods on a more comparable basis. Adjusted funds flow from operations per share is calculated as adjusted funds flow from operations divided by weighted average shares outstanding during the applicable period on a basic or diluted basis.

Average royalty rate

Average royalty rate is a non-GAAP ratio used by management to better analyze the Company's performance against prior periods on a more comparable basis and is calculated as total royalties divided by total sales, net of blending expense, expressed as a percentage.

Effective income tax rate

Effective income tax rate is a non-GAAP ratio used by management to better analyze the Company's cash taxes on a more comparable basis and is calculated as current income tax expense divided by pre-tax adjusted funds flow from operations. Pre-tax adjusted funds flow from operations is calculated as adjusted funds flow from operations before the deduction of current income tax expense.

Supplementary Financial Measures

Per boe numbers

This MD&A represents various results on a per boe basis including net income per boe, financial derivatives gains (losses) per boe, royalty expense per boe, transportation expense per boe, transportation and blending expense per boe, production expense per boe, sales per boe, sales net of blending expense per boe, realized gain (loss) on financial derivatives per boe, general and administrative expenses per boe, interest income and other expense per boe, stock-based compensation expense per boe, depletion and depreciation expense per boe, E&E expense per boe, current income tax expense per boe, deferred income tax expense per boe, total income tax expense per boe, income taxes paid per boe, cash flows provided by operating activities per boe, changes in non-cash working capital per boe and settlement of decommissioning liabilities per boe. These figures are calculated using sales volumes.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

The Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO") of the Company have designed, or caused to be designed under their supervision, disclosure controls and procedures as defined in National Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings* ("NI 52-109") of the Canadian Securities Administrators, to provide reasonable assurance that: (i) information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the Company's management, including the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.

The CEO and the CFO have evaluated the effectiveness of Headwater's disclosure controls and procedures as at December 31, 2025 and have concluded that such disclosure controls and procedures were effective as at such date.

The CEO and the CFO of Headwater have designed, or caused to be designed under their supervision, internal controls over financial reporting ("ICFR") as defined in NI 52-109. The control framework Headwater's officers used to design the Company's ICFR is the COSO Framework published by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). The CEO and CFO have concluded that the Company's ICFR were effective as of December 31, 2025. There have been no changes in the ICFR during the period from October 1, 2025, to December 31, 2025, that have materially affected, or are reasonably likely to materially affect the Company's ICFR.

It should be noted that while Headwater's CEO and CFO believe that the Company's internal controls and procedures provide a reasonable level of assurance and that they are effective, they do not expect these

controls will prevent all errors or fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Critical Accounting Estimates

Use of estimates and judgments

The preparation of the Company's financial statements in accordance with IFRS requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Such estimates and assumptions are evaluated at each reporting date and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Estimates are more difficult to determine, and the range of potential outcomes can be wider, in periods of higher volatility and uncertainty. The impacts of various events such as the Russian invasion of Ukraine, Middle Eastern conflicts (including the recent attacks by the U.S. and Israel on Iran and Iranian retaliation) and the United States interventions in Venezuela, along with the imposition of United States tariffs on Canadian imported goods and their impact on energy markets and general market conditions, increased interest and inflation rates and supply chain uncertainties have created a higher level of volatility and uncertainty. Management has, to the extent reasonable, incorporated known facts and circumstances into the estimates made however, actual results could differ from those estimates and those differences could be material. The Company has also identified the below as an area requiring significant judgments, assumptions or estimates:

Tariffs

Since the inauguration of Donald Trump as President of the United States, U.S. tariffs on certain Canadian products, including energy, along with Canada's reciprocal measures, have added complexity to cross-border energy trade. The U.S.-Canada tariff environment remains volatile, with tariffs and duties affecting products that do not qualify for United States-Mexico-Canada Agreement ("USMCA") exemptions. On February 20, 2026 the Supreme Court of the United States released its ruling that the President did not have the authority under the International Emergency Economic Powers Act to impose tariffs. Following the ruling of the Supreme Court, the Trump administration immediately announced that it would use other legislation to impose tariffs.

At the present time, there are no tariffs on Canadian energy products that are exported into the United States provided that such products qualify under the United States-Mexico-Canada Agreement ("USMCA") (all of the Company's energy products currently qualify under the USMCA). However, the upcoming 2026 USMCA review adds further uncertainty for Canadian exports (including energy products) to the United States. These dynamics influence export costs, market access, and demand for Canadian energy products. If there are significant changes to USMCA or USMCA is not renewed it could have a material adverse effect on the Canadian economy including the oil and gas industry and the Company. In addition, any tariffs imposed on Canadian energy exports into the United States could have a material adverse effect on the Canadian oil and gas industry and the Company's business. The Company will continue to monitor the impact of this evolving situation.

Climate change and alternative energy sources

The following provides certain disclosures as to the impact of climate change on the amounts recorded in the financial statements as at and for the year ended December 31, 2025. The below is not a comprehensive list or analysis of all climate change impacts and risks.

Emissions, carbon and other regulations impacting climate and climate related matters are constantly evolving. In recent years, the Canadian Sustainability Standards Board ("CSSB") worked to advance and adopt Canadian climate-related reporting standards based on international climate-related reporting standards. In addition, the Canadian Securities Administrators ("CSA") had begun their own consultation

process to determine how CSSB's reporting standards would be translated into reporting requirements for reporting issuers and the timing for the implementation of such mandatory reporting requirements; however, on April 23, 2025, the CSA announced that it would be pausing work on the development of new climate related reporting requirements due to current global economic and geopolitical uncertainty and rising competitive concerns for Canadian issuers. The CSA has noted that it expects to revisit the adoption of climate related disclosures in the future. To the extent that any new climate or sustainability related standards are adopted in the future, the Company would likely incur additional costs to comply with such standards.

The Company has considered the impact of the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels in its assessment as a possible indication of impairment of its oil and gas properties. The Company completed the analysis of triggers for impairment as at December 31, 2025, and climate risk/climate change, in of itself, did not result in the Company completing an impairment test. The Company has considered the impact of the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels in its assessment of depletion on its oil and gas properties. Depletion of the Company's oil and gas properties was based on proved and probable reserves, the life of which is generally less than 40 years. The ultimate period in which global energy markets can transition from carbon-based sources to alternative energy is highly uncertain, however, the majority of the Company's proved and probable reserves per the 2025 reserve report should be realized prior to the elimination of carbon-based energy. At this time, the Company has not capped its reserve life for purposes of calculating depletion expense, however, this estimate will be monitored as the energy evolution continues.

The Company engages a third-party external reserve engineer to prepare the reserve report. The reserve report includes anticipated impacts from emissions related taxes, most notably the reserve report includes estimated carbon tax related to the Company's operations consistent with the Emissions Management and Climate Resilience Act (Alberta).

The evolving energy transition and general public sentiment to the oil and gas industry may result in reduced access to capital markets. Management will continue to adjust the capital structure as necessary in response to changing industry conditions.

The Company maintains insurance coverage that provides a level of insurance for certain events that may arise due to climate change factors; however, the Company's insurance program is subject to limits and various restrictions. No claims were made under the Company's insurance policies in 2025 with respect to climate related matters.

Critical Judgments in Applying Accounting Policies

Determination of cash-generating units ("CGU") and impairment

The determination of what constitutes a CGU used to test the recoverability of the carrying values of the Company's oil and gas properties is subject to management's judgment. Judgments are made in regard to shared infrastructure, geographical proximity, petroleum type and similar exposure to market risks and materiality. The asset composition of a CGU can directly impact the recoverability of the assets included therein.

Judgments are required to assess when impairment or impairment reversal indicators exist, and when impairment testing is required.

E&E assets

The application of the Company's accounting policy for E&E assets requires management to make certain judgments as to whether economic quantities of reserves have been found. Judgment is also required to determine the level at which E&E is assessed for impairment; for Headwater, the recoverable amount of E&E assets is assessed at a CGU level.

Key Sources of Estimation Uncertainty

Recoverability of asset carrying value and the impact of reserves on depletion and the evaluation of the recoverable amount of a CGU

At each reporting date, the Company assesses its property, plant and equipment and E&E assets to determine if there is any indication that the carrying amount of the assets may not be recoverable. An assessment is also made at each reporting date to determine whether there is any indication that previously recognized impairment losses no longer exist or have decreased. Determination as to whether and how much an asset is impaired, or no longer impaired, involves management's estimates on highly uncertain matters. The key estimates used in the determination of cash flows from crude oil and natural gas reserves and the volume of proved and probable crude oil and natural gas reserves include the following:

- Reserves and forecasted production – assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in future price estimates, production levels or results of future drilling may change the economic status of reserves and may ultimately result in reserve revisions.
- Forecasted crude oil and natural gas prices – commodity prices can fluctuate for a variety of reasons including supply and demand fundamentals, inventory levels, exchange rates, weather, and economic and geopolitical factors.
- Discount rate – the discount rate used to calculate the net present value of cash flows is based on estimates of an approximate industry peer group weighted average cost of capital. Changes in the general economic environment could result in significant changes to this estimate.
- Forecasted operating and royalty costs and future development costs – estimates concerning future drilling and infrastructure costs and production costs required to operate the assets are used in the cash flow model.

Changes in circumstances may impact these estimates which could have a material financial impact in future periods.

Reserves estimates also have a material financial impact on depletion expense and decommissioning liabilities, all of which could have a material impact on financial results. These reserve estimates are evaluated by third-party reserve evaluators at least annually, who work with information provided by the Company to establish reserve determinations in accordance with National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Changes in circumstances may impact these estimates which could have a material financial impact in future periods.

Decommissioning liabilities

The decommissioning costs which will ultimately be incurred by the Company are uncertain and estimates can vary in response to many factors including changes to regulatory requirements, changes to relevant legal requirements, the emergence of new restoration techniques or experience at other production sites. The expected timing can also change in response to changes in reserves or changes in laws and regulations. As a result, there could be significant adjustments to the provisions established which could materially affect future financial results. Judgments include the most appropriate discount rate to use, which management has determined to be a risk-free rate, as well as the underlying cost estimates as they are derived from a combination of published industry benchmarks as well as site specific information.

Valuation of financial instruments

The estimated fair values of the Company's financial derivative commodity contracts are subject to measurement uncertainty due to the estimation of future crude oil and natural gas commodity prices and volatility.

Valuation of performance share units (“PSUs”)

The estimate of stock-based compensation in respect of the Company’s PSUs is dependent on the performance multiplier estimated by management.

Recently announced accounting pronouncements

IFRS 18 “Presentation and disclosure in financial statements” has been issued which will replace IAS 1 “Presentation of financial statements”. The new standard will introduce new totals, subtotals, and categories for income and expenses in the statements of income and comprehensive income, as well as requiring disclosure about management-defined performance measures and additional requirements regarding the aggregation and disaggregation of certain information. IFRS 18 is effective for annual periods beginning on or after January 1, 2027 and will be applied retroactively. The Company is currently evaluating the impact of adopting IFRS 18 on the financial statements.

Amendments to IFRS 9 “Financial Instruments and IFRS 7 Financial Instruments: Disclosures” have been issued with the intention to clarify the date of recognition and derecognition of some financial assets and liabilities. The amendments are effective January 1, 2026, with early adoption permitted. The Company is currently evaluating the impact of these amendments on the financial statements.

Business Conditions and Risks

There are numerous factors both known and unknown, that could cause actual results or events to differ materially from forecast results. The following is a summary of such risk factors, which should not be construed as exhaustive:

- Volatility in the market conditions for the oil and natural gas industry may affect the value of the Company's reserves and restrict its cash flow and ability to access capital to fund the development of its properties;
- The risk that (i) the United States, Canadian or other foreign governments implement, maintain or increase the rate or scope of new tariffs or impose other restrictive measures on imports and exports of products, and (ii) the review of USMCA results in renegotiation of the terms or withdrawal by one of the countries that is party thereto, which could have a material adverse effect on the Canadian, U.S. and global economies, and by extension the Canadian oil and natural gas industry and the Company;
- Various factors may adversely impact the marketability of oil and natural gas, affecting net production revenue, production volumes and development and exploration activities;
- The anticipated benefits of acquisitions may not be achieved and the Company may dispose of non-core assets for less than their carrying value on the financial statements as a result of weak market conditions;
- The impacts of the Russian-Ukrainian conflict, the Middle East conflicts (including the U.S., Israel and Iran conflict) and the United States intervention in Venezuela on commodity prices, supply and demand factors for energy products and the world economy could affect the Company's results, business, financial conditions or liquidity;
- Natural disasters, terrorist acts, civil unrest, war, pandemics and other disruptions and dislocations may affect the Company's results, business, financial conditions or liquidity;
- The Company's business may be adversely affected by political and social events and decisions made in Canada, the United States, Europe and elsewhere;

- Lack of capacity and/or regulatory constraints on gathering and processing facilities and pipeline systems may have a negative impact on the Company's ability to produce and sell its oil and natural gas;
- The Company competes with other oil and natural gas companies, some of which have greater financial and operational resources;
- The Company's ability to successfully implement new technologies into its operations in a timely and efficient manner will affect its ability to compete;
- Changes to the demand for oil and natural gas products and the rise of petroleum alternatives may negatively affect the Company's financial condition, results of operations and cash flow;
- Modification to current, or implementation of additional, regulations (including environmental regimes) or royalty regimes may reduce the demand for oil and natural gas, impact the Company's cash flows and/or increase the Company's costs and/or delay planned operations;
- Taxes on carbon emissions may affect the demand for oil and natural gas, the Company's operating expenses and may impair the Company's ability to compete;
- Liability management programs enacted by regulators in the western provinces may prevent or interfere with the Company's ability to acquire properties or require a substantial cash deposit with the regulator;
- The Company may require additional financing, from time to time, to fund the acquisition, exploration and development of properties and its ability to obtain such financing in a timely fashion and on acceptable terms may be negatively impacted by the current economic and global market volatility;
- Changing investor sentiment towards the oil and natural gas industry may impact the Company's access to, and cost of, capital;
- Oil and natural gas operations are subject to seasonal weather conditions and, if applicable to the Company's operations in the future, the Company may experience significant operational delays as a result;
- Regulatory water use restrictions and/or limited access to water or other fluids may impact the Company's future production volumes from any future waterflood of the Company;
- Credit risk related to non-payment for sales contracts or other counterparties;
- Foreign exchange risk as commodity sales are based on U.S. dollar denominated benchmarks; and
- The risk of significant interruption or failure of the Company's information technology systems and related data and control systems or a significant breach that could adversely affect the Company's operations.

Additional risks and information on risk factors are included in the Annual Informational Form for the year ended December 31, 2025, dated March 5, 2026, which is available on the Company's website at www.headwaterexp.com and under the Company's profile on SEDAR+ at www.sedarplus.ca.

The Company uses a variety of means to help mitigate or minimize these risks including the following:

- Attracting and retaining a team of highly qualified and motivated professionals who have a vested interest in the success of the Company;
- Employing risk management instruments to minimize exposure to volatility of commodity prices;
- Maintaining a strong financial position;
- Maintaining strict environmental, safety and health practices;
- Maintaining a comprehensive insurance program;
- Managing credit risk by entering into agreements with counterparties that are highly credit worthy or investment grade; and
- The implementation of cyber security protocols and procedures to reduce to risk of failure of breach of data.

Oil and Gas

The term barrels of oil equivalent (“boe”) may be misleading, particularly if used in isolation. Per boe amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil. This equivalence is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil 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.

References to heavy oil, natural gas, and natural gas liquids in the MD&A refer to heavy crude oil, conventional natural gas and natural gas liquids, respectively, product types as defined in NI 51-101.

Dividend Policy

The amount of future cash dividends paid by the Company, if any, will be subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including, among other things, adjusted funds flow from operations, fluctuations in commodity prices, production levels, capital expenditure requirements, acquisitions, debt service requirements and debt levels, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond the control of the Company, the Board will adjust the Company’s dividend policy from time to time and, as a result, future cash dividends could be reduced or suspended entirely.

Reserves Information

Reserves information as at December 31, 2025 as presented herein is based on a report (the “2025 Reserves Report”) prepared by McDaniel & Associates Consultants Ltd. (“McDaniels”) assessing the Company’s reserves effective December 31, 2025 which were prepared in accordance with standards of the Canadian Oil and Gas Evaluation Handbook and NI 51-101 and is based on the average forecast prices as at December 31, 2025 of three independent reserves evaluation firms. Additional information regarding reserves data and other oil and gas information is included in Headwater’s Annual Information Form for the year ended December 31, 2025, dated March 5, 2026, which is available on the Company’s website at and under the Company’s profile on SEDAR+ at www.sedarplus.ca.

Forward Looking Information

This MD&A contains certain forward-looking statements and forward-looking information (collectively referred to herein as “forward-looking statements”) within the meaning of Canadian securities laws. All statements other than statements of historical fact are forward-looking statements. Forward-looking information typically contains statements with words such as “anticipate”, “believe”, “plan”, “continuous”, “estimate”, “expect”, “may”, “will”, “project”, “should” or similar words suggesting future outcomes. In particular, this MD&A contains forward-looking statements pertaining to the following:

- business plans and strategies;
- the possibility that the Company may mitigate a portion of its risk by entering into foreign exchange contracts;
- the percentage of royalty rate payable by Headwater under the Alberta Modernized Royalty Framework;
- the anticipated vesting dates of PSUs and RSUs;
- the Company’s intent to settle PSUs, RSUs and DSUs in cash;
- the Company’s intent to not grant any further options under the stock option plans;

- the estimated undiscounted uninflated amount of cash flows required to settle the Company's decommissioning liabilities;
- Headwater's expectation to fund capital expenditures through existing working capital and forecasted cash flows from operating activities;
- 2026 crude oil and natural gas pricing assumptions;
- 2026 Canadian – U.S. dollar exchange rates;
- 2026 guidance related to annual production, capital expenditures, dividends and adjusted funds flow from operations;
- the Company's objectives for managing its capital, the anticipated benefits to be derived therefrom and the anticipated means of achieving such objectives;
- the expectation that the Company has adequate liquidity to fund its 2026 capital expenditure budget and future dividend payments through existing working capital and forecasted adjusted funds flow from operations;
- the expectation that Headwater could make use of additional equity or debt financings to fund any substantial expansion of its capital program or finance any significant acquisitions;
- the possibility that Headwater may issue equity as consideration to complete any future acquisitions;
- the Company's future contractual obligations and commitments;
- expectations regarding the repayment of NRCan in connection with the Project and the timing thereof;
- the intended results of the Project;
- the anticipated terms of the Company's quarterly dividend, including its expectation that it will be designated as an "eligible dividend";
- the expectation that the majority of the Company's proved and probable reserves per the 2025 reserve report should be realized prior to the elimination of carbon-based energy;
- the expectation that the energy transition and general public sentiment to oil and gas may reduce access to capital markets and the expectation that the Company will adjust its capital structure as necessary in response to changing industry conditions;
- the Company's intent to evaluate the potential effects of the new sustainability standards and any steps taken by the CSA to adopt the new standards as reporting requirements for reporting issuers and the expectation that the Company would incur additional costs to comply with any such standards; and
- the Company's dividend policy.

Statements relating to "reserves" are forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves described, as applicable, exist in the quantities predicted or estimated and can profitably be produced in the future. Undue reliance should not be placed on forward-looking statements, which are inherently uncertain, are based on estimates and assumptions, and are subject to known and unknown risks and uncertainties (both general and specific) that contribute to the possibility that the future events or circumstances contemplated by the forward-looking statements will not occur. There can be no assurance that the plans, intentions or expectations upon which forward-looking statements are based, will in fact be realized. Actual results will differ, and the difference may be material and adverse to the Company and its shareholders.

The forward-looking statements contained herein are based on certain key expectations and assumptions made by the Company, including but not limited to: the potential impact of tariffs that may be implemented by the U.S. and Canadian governments, and that neither the U.S. nor Canada (i) increases the rate or scope of such tariffs, 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; expectations and assumptions concerning the success of optimization and efficiency improvement projects, the availability of capital, current legislation, receipt of required regulatory approval, the success of future drilling, development and waterflooding activities, the performance of existing wells, the performance of new wells, Headwater's growth strategy, general economic conditions including inflationary pressures, availability of required equipment and services, prevailing equipment and services costs and prevailing commodity

prices. Although the Company believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because the Company can give no assurance that they will prove to be correct.

This MD&A contains information that may be considered a financial outlook or future-oriented financial information under applicable securities laws about the Company's potential financial position, including but not limited to: the Company's 2026 budget and guidance related to capital expenditures, dividends and adjusted funds flow from operations; the Company's future contractual obligations and commitments; and the estimated undiscounted uninflated amount of cash flows required to settle the Company's decommissioning liabilities. Any financial outlook or future-oriented financial information in this MD&A, as defined by applicable securities legislation, has been approved by management of the Company as of the date hereof. Readers are cautioned that any such future-oriented financial information contained herein should not be used for purposes other than those for which it is disclosed herein. The Company and its management believe that the prospective financial information as to the anticipated results of its proposed business activities for the periods specified herein has been prepared on a reasonable basis, reflecting management's best estimates and judgments, and represent, to the best of management's knowledge and opinion, the Company's expected course of action. However, because this information is highly subjective, it should not be relied on as necessarily indicative of future results. The assumptions used in the 2026 guidance include: annual average production of 24,500 boe/d, WTI of US\$60.00/bbl, WCS of Cdn\$67.00/bbl, AGT US\$10.60/mmbtu, AECO of \$3.10 CAD/GJ, foreign exchange rate of US\$/Cdn\$ of 0.72, blending expense of WCS less \$1.10, royalty rate of 17.2%, operating and transportation costs of \$14.15/boe, G&A and interest expense of \$1.60/boe and cash taxes of \$3.30/boe. The AGT price is the average price for the winter producing months in the McCully field which include January to April and December. 2026 annual production guidance is expected to be comprised of: 22,500 bbls/d of heavy oil, 120 bbls/d of natural gas liquids and 11.3 mmcf/d of natural gas.

Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risks identified under the heading "*Business Conditions and Risks*". Further information regarding these factors and additional factors may be found under the heading "Risk Factors" in the Annual Informational Form for the year ended December 31, 2025, dated March 5, 2026, which is available on the Company's website at www.headwaterexp.com and under the Company's profile on SEDAR+ at www.sedarplus.com. Readers are cautioned that the foregoing list of factors that may affect future results is not exhaustive.

The forward-looking statements contained in this MD&A are made as of the date hereof and the Company does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, except as required by applicable law. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

Corporate Information

Board of Directors

NEIL ROSZELL
Executive Chairman, Headwater Exploration Inc.
Calgary, Alberta

JASON JASKELA
President and CEO, Headwater Exploration Inc.
Calgary, Alberta

CHANDRA HENRY ⁽¹⁾ ⁽²⁾
CFO and Chief Compliance Officer, Longbow Capital Inc.
Calgary, Alberta

STEPHEN LARKE ⁽²⁾ ⁽⁴⁾
Director, Vermillion Energy Inc. and Topaz Energy Corp.
Calgary, Alberta

KEVIN OLSON ⁽³⁾ ⁽⁴⁾
Independent Businessman
Calgary, Alberta

DAVE PEARCE ⁽²⁾ ⁽³⁾
Deputy Chairman, Azimuth Capital Management
Calgary, Alberta

KAM SANDHAR ⁽¹⁾ ⁽³⁾
Executive Vice President and CFO, Cenovus Energy Inc.
Calgary, Alberta

CHEREE STEPHENSON ⁽¹⁾ ⁽⁴⁾
Vice President Finance and CFO, Topaz Energy Corp.
Calgary, Alberta

KAREN NIELSEN ⁽³⁾ ⁽⁴⁾
Independent Businesswoman
Calgary, Alberta

TED BROWN (Corporate Secretary)
Burnet, Duckworth & Palmer LLP
Calgary, Alberta

- (1) Audit Committee
- (2) Corporate Governance and Compensation Committee
- (3) Reserves Committee
- (4) Environment, Safety and Sustainability Committee

Website: www.headwaterexp.com

Officers

NEIL ROSZELL, P. Eng.
Executive Chairman

JASON JASKELA, P. Eng.
President and CEO

ALI HORVATH, CPA, CA
Chief Financial Officer

TERRY DANKU, P. Eng.
Executive Vice President

BRAD CHRISTMAN
Chief Operating Officer

DIETER DEINES
Vice President Exploration

SCOTT RIDEOUT
Vice President Land

GEORGIA LITTLE, CPA, CA
Vice President Finance

WADE HEIN
Vice President Operations

JEFF MAGEE
Vice President Engineering

Head Office

Suite 1400, 215 – 9th Avenue SW
Calgary, Alberta T2P 1K3
Tel: (587) 391-3680

Auditors

KPMG LLP
Calgary, AB

Independent Reservoir Consultants

McDaniel & Associates Consultants Ltd.
Calgary, AB