Q2 2026 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 July 23, 2026 and should be read in conjunction with the unaudited interim condensed financial statements ("interim financial statements") as at and for the three and six months ended June 30, 2026, and the MD&A and the audited financial statements and the notes thereto for the year ended December 31, 2025, copies of which are available through SEDAR+ at www.sedarplus.ca. The unaudited interim financial statements have been prepared in accordance with IAS 34 *Interim Financial Reporting* as issued by the International Accounting Standards Board. All dollar amounts are referenced in Canadian dollars unless otherwise stated.

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 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.

HIGHLIGHTS FOR THREE MONTHS ENDED JUNE 30, 2026

- Achieved record production of 24,567 boe/d representing an increase of 10% from the second quarter of 2025.
- Realized record adjusted funds flow from operations (1) of $117.7 million ($0.50 per share basic (2)) and cash flows from operations of $134.6 million ($0.57 per share basic).
- Achieved an operating netback, including financial derivatives (2) of $59.88/boe and an adjusted funds flow netback (2) of $52.54/boe.
- Achieved record net income of $85.4 million ($0.36 per share basic) equating to $38.11/boe.
- Executed an $81.6 million capital expenditure (3) program inclusive of development, land, exploration expenditures and secondary recovery implementation.
- Declared a cash dividend of $28.5 million, or $0.12 per common share. To date, Headwater has paid out a cumulative dividend of $372.3 million to shareholders ($1.57 per common share).
- As at June 30, 2026, Headwater had adjusted working capital (1) of $9.0 million, working capital of $10.2 million, and no outstanding bank debt.

(1) Capital management measure. Refer to "Management of capital" in note 12 of the interim financial statements and to "Non-GAAP and Other Financial Measures" within this MD&A.
(2) Non-GAAP ratio. Refer 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.

RESULTS OF OPERATIONS

Production and Pricing

	Three months ended June 30, 2026	Three months ended June 30, 2025	Percent Change	Six months ended June 30, 2026	Six months ended June 30, 2025	Percent Change
Average daily production						
Heavy oil (bbls/d)	23,046	20,249	14	22,455	19,882	13
Natural gas (mmcf/d)	8.2	10.8	(24)	10.6	12.6	(16)
Natural gas liquids (bbls/d)	148	185	(20)	142	164	(13)
Barrels of oil equivalent (boe/d)	24,567	22,235	10	24,362	22,151	10
Average daily sales [1]						
Heavy oil (bbls/d)	23,106	20,136	15	22,374	19,802	13
Natural gas (mmcf/d)	8.2	10.8	(24)	10.6	12.6	(16)
Natural gas liquids (bbls/d)	148	185	(20)	142	164	(13)
Barrels of oil equivalent (boe/d)	24,627	22,123	11	24,281	22,071	10
Headwater average sales price [2]						
Heavy oil ($/bbl) [3]	106.71	73.75	45	93.21	78.64	19
Natural gas ($/mcf)	2.13	2.22	(4)	8.81	7.35	20
Natural gas liquids ($/bbl)	104.11	70.38	48	89.73	74.87	20
Barrels of oil equivalent ($/boe)	101.45	68.80	47	90.26	75.32	20
Average Benchmark Price						
WTI (US$/bbl) [4]	92.79	63.74	46	82.36	67.58	22
WCS differential to WTI (US$/bbl)	(14.66)	(10.27)	43	(14.41)	(11.47)	26
WCS (Cdn$/bbl) [5]	107.97	74.00	46	93.60	79.08	18
Condensate at Edmonton (Cdn$/bbl)	131.42	87.43	50	114.56	93.53	22
AGT (US$/mmbtu) [6]	2.28	3.14	(27)	11.13	9.66	15
AECO 5A (Cdn$/GJ)	1.45	1.60	(9)	1.68	1.83	(8)
NYMEX Henry Hub (US$/mmbtu)	2.90	3.47	(16)	3.97	3.56	12
Exchange rate (Cdn$ to US$)	0.72	0.72	-	0.73	0.71	3

(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 heavy oil 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 to April and December.

	Three months ended June 30, 2026	Three months ended June 30, 2025	Percent Change	Six months ended June 30, 2026	Six months ended June 30, 2025	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Heavy oil sales	234,629	141,282	66	394,552	294,966	34
Blending expense	(10,262)	(6,136)	67	(17,078)	(13,103)	30
Heavy oil, net of blending expense [1]	224,367	135,146	66	377,474	281,863	34
Natural gas	1,599	2,183	(27)	16,890	16,806	-
Natural gas liquids	1,403	1,187	18	2,303	2,219	4
Gathering, processing and transportation	297	292	2	904	1,108	(18)
Total sales, net of blending expense [1]	227,666	138,808	64	397,571	301,996	32

(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 was significantly higher year over year, supported by heightened geopolitical tensions in the Middle East, including the U.S.–Israel–Iran conflict and concerns over disruptions to global oil supplies. Prices moderated toward the end of June following a ceasefire and the reopening of the Strait of Hormuz. Offsetting the impact of higher WTI pricing was the widening of the WCS differential to WTI, reflecting increased volatility in heavy oil markets including changes in North American heavy crude oil supply and demand alongside transportation constraints. The Canadian dollar started to weaken toward the end of the second quarter of 2026, further contributing to higher pricing.

Headwater's discount to WCS widened during the three months ended June 30, 2026, compared to the corresponding period of the prior year, reflecting the impact of apportionment, which increased the proportion of volumes marketed through spot sales at lower realized prices. Headwater's discount to WCS was consistent for the six months ended June 30, 2026, compared to the corresponding period of the prior year.

During the three months ended June 30, 2026, Headwater's heavy oil sales, net of blending expense, increased to $224.4 million from $135.1 million in the corresponding period of 2025. This significant increase was attributable to a 45% increase in realized commodity pricing, consistent with the increase in benchmark WCS pricing, and a 15% increase in sales volumes.

During the six months ended June 30, 2026, Headwater's heavy oil sales, net of blending expense, increased to $377.5 million from $281.9 million in the corresponding period of 2025. This significant increase was attributable to a 19% increase in realized commodity pricing, consistent with the increase in benchmark WCS pricing, and a 13% increase in sales volumes.

During the three and six months ended June 30, 2026, Headwater's heavy oil sales volumes averaged 23,106 bbls/d and 22,374 bbls/d, respectively, compared to 20,136 bbls/d and 19,802 bbls/d in the corresponding periods of 2025. 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 net crude oil wells during the year ended December 31, 2025, and drilled 26.0 net crude oil wells in the first half of 2026, 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 upcoming summer season effective April 30, 2026. 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 the three months ended June 30, 2026, Headwater's natural gas sales decreased to $1.6 million from $2.2 million in the corresponding period of the prior year, due to a decrease in both realized commodity pricing and natural gas sales volumes. Realized natural gas pricing decreased due to lower benchmark pricing for both AGT and AECO 5A. The Company's natural gas sales were relatively consistent for the six months ended June 30, 2026, when compared to the corresponding period of the prior year.

During the three and six months ended June 30, 2026, Headwater's natural gas sales volumes decreased to 8.2 mmcf/d and 10.6 mmcf/d, respectively, from 10.8 mmcf/d and 12.6 mmcf/d in the corresponding periods of the prior year, primarily as a result of lower natural gas sales volumes from Alberta, driven by reduced gas-oil ratios as a result of secondary recovery implementation in Marten Hills West.

Financial Derivative Gains (Losses)

	Three months ended June 30, 2026	2025	Percent Change	Six months ended June 30, 2026	2025	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Realized losses	(11,865)	(722)	1,543	(17,331)	(3,888)	346
Unrealized gains (losses)	13,985	2,082	572	2,015	(404)	(599)
Financial derivative gains (losses)	2,120	1,360	56	(15,316)	(4,292)	257
Per boe	0.95	0.68	40	(3.48)	(1.07)	225

Natural gas and crude oil commodity contracts

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

Realized financial derivative losses of $11.9 million for the three months ended June 30, 2026, primarily reflect losses on the Company's WTI fixed price contract, partially offset by realized gains on its natural gas fixed price contracts (AECO 5A and AGT) and WCS differential contracts. Realized losses on Headwater's WTI fixed price contract totalled $12.9 million, as WTI benchmark pricing settled significantly above the contracted fixed price of Cdn$95.03/bbl throughout the quarter. In June 2026, the Company unwound the remaining term of the WTI contract, covering the period from June through December 2026, to mitigate further realized losses amid heightened commodity price volatility and increased market uncertainty. Realized gains on Headwater's natural gas fixed price contracts totalled $667 thousand, while realized gains on Headwater's WCS differential contracts totalled $409 thousand, during the three months ended June 30, 2026.

The incremental losses recognized in the six months ended June 30, 2026, primarily represent Headwater's McCully natural gas contracts referenced to AGT and the Company's crude oil contract referenced to WTI, discussed above. During the first quarter of 2026, Headwater recognized $3.4 million of losses on its AGT contracts as the commodity contracts to fix the AGT price averaged Cdn$14.81/mmbtu, compared to the average settlement price of Cdn$19.27/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. The Company recognized $2.3 million of losses on its WTI contract during the first quarter of 2026.

The unrealized gains recorded during the three and six months ended June 30, 2026, are a result of the change in fair value of the Company's outstanding financial derivative commodity contracts over the periods. As at June 30, 2026, the fair value of Headwater's outstanding financial derivative commodity contracts was a net unrealized asset of $1.2 million as reflected in the interim financial statements. The fair value or mark to market value of these contracts is based upon the estimated amount that would have been payable as at June 30, 2026, 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 June 30, 2026. For the three and six months ended June 30, 2026, Headwater recognized unrealized gains of $14.0 million and $2.0 million, respectively, compared to unrealized gains of $2.1 million and unrealized losses of $404 thousand in the corresponding periods of 2025.

As at June 30, 2026, Headwater had the following financial derivative commodity contracts outstanding:

Commodity	Index	Type	Term	Daily Volume	Contract Price
Natural Gas	AGT	Fixed	Dec 2026 – Mar 2027	5,000 mmbtu	Cdn$17.88/mmbtu
Natural Gas	AECO 5A	Fixed	Jul 2026 – Oct 2026	4,000 GJ	Cdn$2.49/GJ
Natural Gas	AECO 5A	Fixed	Apr 2027 – Oct 2027	1,000 GJ	Cdn$2.00/GJ
Crude Oil	WCS Basis	Differential	Jul 2026 – Dec 2026	2,000 bbl	US$13.00/bbl

Subsequent to June 30, 2026, the Company entered into an additional financial derivative commodity contract. Refer to the heading "Subsequent Events".

Foreign exchange contracts

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 June 30, 2026, Headwater did not have any foreign exchange contracts outstanding.

Royalty Expense

	Three months ended June 30, 2026	Three months ended June 30, 2025	Percent Change	Six months ended June 30, 2026	Six months ended June 30, 2025	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Royalty expense	49,509	25,847	92	76,350	54,512	40
Average royalty rate (1)	21.7%	18.6%	17	19.2%	18.1%	6
Per boe	22.09	12.84	72	17.37	13.65	27

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

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 will pay 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 commodity reference pricing.

For the three and six months ended June 30, 2026, royalty expense increased to $49.5 million and $76.4 million, respectively, from $25.8 million and $54.5 million in the corresponding periods of 2025, due to higher heavy oil sales, net of blending expense and an increase in the average royalty rate over the periods.

For the three and six months ended June 30, 2026, the average royalty rate increased to 21.7% and 19.2%, respectively, from 18.6% and 18.1% in the corresponding periods of the prior year, primarily attributable to a higher Government of Alberta published heavy oil par price, underpinned by higher benchmark commodity pricing. In addition, higher commodity reference prices accelerated the transition of new wells from the initial 5% flat royalty rate to the post-payout sliding-scale royalty regime, further increasing the average royalty rate during the periods.

Transportation Expense

	Three months ended June 30, 2026	2025	Percent Change	Six months ended June 30, 2026	2025	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Transportation expense	13,574	11,371	19	26,041	22,098	18
Per boe	6.06	5.65	7	5.93	5.53	7

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

For the three and six months ended June 30, 2026, transportation expense increased to $13.6 million and $26.0 million, respectively, from $11.4 million and $22.1 million in the corresponding periods of the prior year, primarily as a result of an increase to heavy oil sales volumes.

For the three and six months ended June 30, 2026, transportation expense per boe increased to $6.06 and $5.93, respectively, from $5.65 and $5.53 in the corresponding periods of the prior year, due to higher trucking costs.

In the third quarter of 2026, Headwater started construction on an oil transportation pipeline connecting 17,000 bbls/d of heavy oil from the Marten Hills West operating area into the Company's sales-connected 08-34-074-25W4 oil processing facility in the core area of Marten Hills. Once commissioned, which is expected to occur in the first half of 2027, more than 90% of Headwater's heavy oil production volumes will be pipeline connected. This project is anticipated to generate more than $20 million per year, or $2.00 per boe, in operating/transportation cost savings.

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 June 30, 2026	2025	Percent Change	Six months ended June 30, 2026	2025	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Production expense	18,527	14,986	24	36,177	30,692	18
Per boe	8.27	7.44	11	8.23	7.68	7

For the three and six months ended June 30, 2026, production expense increased to $18.5 million and $36.2 million, respectively, from $15.0 million and $30.7 million in the corresponding periods of 2025, primarily as a result of higher production volumes.

For the three and six months ended June 30, 2026, production expense per boe increased to $8.27 and $8.23, respectively, from $7.44 and $7.68 in the corresponding periods of the prior year, due to wetter spring conditions resulting in higher road maintenance and field access costs.

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 June 30, 2026	Three months ended June 30, 2025	Percent Change	Six months ended June 30, 2026	Six months ended June 30, 2025	Percent Change
	($/boe)			*($/boe)*		
Sales	106.17	72.00	47	94.35	78.89	20
Royalties	(22.09)	(12.84)	72	(17.37)	(13.65)	27
Transportation and blending	(10.64)	(8.70)	22	(9.81)	(8.81)	11
Production expense	(8.27)	(7.44)	11	(8.23)	(7.68)	7
Operating netback (1)	65.17	43.02	51	58.94	48.75	21
Realized losses on financial derivatives	(5.29)	(0.36)	1,369	(3.94)	(0.97)	306
Operating netback, including financial derivatives (1)	59.88	42.66	40	55.00	47.78	15

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

For the three and six months ended June 30, 2026, the Company's operating netback, including financial derivatives, increased to $59.88 per boe and $55.00 per boe, respectively, from $42.66 per boe and $47.78 per boe in the corresponding periods of 2025. The increase in operating netback, including financial derivatives in both the three and six months ended June 30, 2026, is primarily due to higher realized heavy oil pricing, partially offset by higher royalties and realized losses on financial derivatives, driven by higher commodity pricing, alongside higher transportation and blending and production expenses over the prior periods.

General and Administrative ("G&A") Expenses

	Three months ended June 30, 2026	Three months ended June 30, 2025	Percent Change	Six months ended June 30, 2026	Six months ended June 30, 2025	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
G&A expenses	4,577	3,891	18	9,091	7,755	17
Capitalized G&A	(1,191)	(987)	21	(2,532)	(2,002)	26
Net G&A expenses	3,386	2,904	17	6,559	5,753	14
Per boe ($)	1.51	1.44	5	1.49	1.44	3

For the three and six months ended June 30, 2026, net G&A expenses increased to $3.4 million and $6.6 million, respectively, from $2.9 million and $5.8 million in the corresponding periods of 2025. Increased net G&A expenses on an absolute basis were mainly a result of increased employee related costs due to the growth experienced by the Company over the periods. G&A expenses per boe were relatively consistent over the periods.

Interest Income and Other Expense

	Three months ended June 30, 2026	Three months ended June 30, 2025	Percent Change	Six months ended June 30, 2026	Six months ended June 30, 2025	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Interest income	485	924	(48)	1,075	2,079	(48)
Realized and unrealized foreign exchange gains	18	6	200	18	5	260
Accretion on decommissioning liability	(356)	(428)	(17)	(694)	(832)	(17)
Interest on repayable contribution	(214)	(226)	(5)	(432)	(454)	(5)
Interest on lease liability	(38)	(50)	(24)	(80)	(100)	(20)
Total interest income and other expense	(105)	226	(146)	(113)	698	(116)
Per boe ($)	(0.05)	0.11	(145)	(0.03)	0.17	(118)

For the three and six months ended June 30, 2026, interest income and other expense decreased from $226 thousand and $698 thousand, respectively, to an expense of $105 thousand and $113 thousand, primarily due to lower interest income. The decrease in interest income is a result of carrying a lower average cash balance, when compared to the same periods in 2025, coupled with a decrease in the average interest rate earned over the periods, driven by a lower prime rate in 2026 compared to 2025.

Stock-based Compensation

	Three months ended June 30, 2026	Three months ended June 30, 2025	Percent Change	Six months ended June 30, 2026	Six months ended June 30, 2025	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Deferred share units (“DSUs”)	(368)	336	(210)	2,171	1,126	93
Share awards	2,935	3,353	(12)	22,197	5,407	311
Capitalized stock-based compensation	(641)	(600)	7	(5,418)	(1,080)	402
Stock-based compensation	1,926	3,089	(38)	18,950	5,453	248
Per boe ($)	0.86	1.53	(44)	4.31	1.36	217

For the three months ended June 30, 2026, stock-based compensation expense decreased to $1.9 million from $3.1 million in the corresponding period of the prior year, driven by lower expense for DSUs and share awards, due to a decrease in Headwater’s share price from $12.85 at March 31, 2026 to $11.83 at June 30, 2026. For the six months ended June 30, 2026, stock-based compensation expense increased to $19.0 million from $5.5 million in the corresponding period of the prior year, primarily driven by higher expense for share awards due to an increase in Headwater’s share price from $9.37 at December 31, 2025, to $11.83 at June 30, 2026, in addition to amortization of existing awards. Stock-based compensation expense for the six months ended June 30, 2025 of $5.5 million was comparatively lower, due to the amortization of existing awards and only a slight increase in Headwater’s share price from $6.61 at December 31, 2024, to $6.73 at June 30, 2025.

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 performance share units (“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. RSUs and PSUs are measured at fair value using the Company’s closing share price on June 30, 2026.

As at June 30, 2026, there were 372 thousand RSUs outstanding and 3,444 thousand PSUs outstanding, representing 1.6% of Headwater’s total common shares issued and outstanding.

Deferred Share Units (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 (the "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 or before 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 June 30, 2026.

As at June 30, 2026, there were 445 thousand DSUs outstanding.

Depletion & Depreciation

	Three months ended June 30,		Percent	Six months ended June 30,		Percent
	2026	2025	Change	2026	2025	Change
	(thousands of dollars)			*(thousands of dollars)*		
Depletion & depreciation	29,720	32,636	(9)	58,665	65,151	(10)
Depletion & depreciation – Per boe ($)	13.26	16.21	(18)	13.35	16.30	(18)

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 and six months ended June 30, 2026, depletion and depreciation expense decreased to $29.7 million and $58.7 million, respectively, from $32.6 million and $65.2 million in the corresponding periods of the prior year, due to lower depletion and depreciation rates, partially offset by an increase in the Company’s production volumes over the periods.

For the three and six months ended June 30, 2026, Headwater’s depletion and depreciation rate decreased to $13.26 per boe and $13.35 per boe, respectively, from $16.21 per boe and $16.30 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 June 30, 2026	Three months ended June 30, 2025	Percent Change	Six months ended June 30, 2026	Six months ended June 30, 2025	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
E&E Expense	1,814	-	100	1,814	-	100
Per boe ($)	0.81	-	100	0.41	-	100

During the three and six months ended June 30, 2026, the Company recognized $1.8 million of E&E expense related to its non-core Alberta assets.

Impairment Assessment

As at June 30, 2026, there are 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 June 30, 2026	Three months ended June 30, 2025	Percent Change	Six months ended June 30, 2026	Six months ended June 30, 2025	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Current income tax expense	13,541	9,683	40	21,080	20,453	3
Deferred income tax expense	12,268	1,855	561	15,523	6,263	148
Total income tax expense	25,809	11,538	124	36,603	26,716	37
Current income tax expense – Per boe ($)	6.04	4.81	26	4.80	5.12	(6)
Deferred income tax expense – Per boe ($)	5.47	0.92	495	3.53	1.57	125
Total income tax expense – Per boe ($)	11.51	5.73	101	8.33	6.69	25

For the three and six months ended June 30, 2026, current income taxes increased to $13.5 million and $21.1 million, respectively, from $9.7 million and $20.5 million in the corresponding periods of the prior year, as a result of higher forecast pre-tax adjusted funds flow from operations for the year ended December 31, 2026 compared to the year ended December 31, 2025, primarily due to higher commodity pricing. Partially offsetting the impact of higher commodity pricing and forecast pre-tax adjusted funds flow from operations is the recognition of accelerated claims for both resource pools and undepreciated capital cost, effective for the period beginning on January 1, 2025, pursuant to Bill C-15, the Budget Implementation Act, 2025, No.1, becoming substantivity enacted and receiving royal assent in the first quarter of 2026.

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

	Three months ended June 30, 2026	Three months ended June 30, 2025	Percent Change	Six months ended June 30, 2026	Six months ended June 30, 2025	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Cash flows provided by operating activities	134,566	68,673	96	174,635	138,608	26
Changes in non-cash working capital	(13,331)	4,122	(423)	40,353	11,010	267
Current income taxes	(13,541)	(9,683)	40	(21,080)	(20,453)	3
Income taxes paid	10,055	9,106	10	21,200	35,412	(40)
Restricted cash	-	2,000	(100)	-	2,000	(100)
Adjusted funds flow from operations (1)	117,749	74,218	59	215,108	166,577	29

For the three and six months ended June 30, 2026, adjusted funds flow from operations increased to $117.7 million and $215.1 million, respectively, from $74.2 million and $166.6 million in the corresponding periods of the prior year, due to a higher adjusted funds flow netback in combination with higher sales volumes over the periods.

For the three months ended June 30, 2026, cash flows provided by operating activities were $134.6 million, $16.8 million higher than adjusted funds flow from operations for the same period of $117.7 million, primarily due to changes in non-cash working capital driven by a decrease in the June 30, 2026, accounts receivable balance as a result of lower commodity pricing in June 2026, compared to March 2026, following the U.S.–Israel–Iran ceasefire and the reopening of the Strait of Hormuz.

For the six months ended June 30, 2026, cash flows provided by operating activities were $174.6 million, $40.5 million lower than adjusted funds flow from operations for the same period of $215.1 million, primarily due to changes in non-cash working capital driven by a $34.5 million payout of stock-based compensation.

	Three months ended June 30, 2026	Three months ended June 30, 2025	Percent Change	Six months ended June 30, 2026	Six months ended June 30, 2025	Percent Change
	($/boe)			*($/boe)*		
Cash flows provided by operating activities	60.04	34.11	76	39.74	34.70	15
Changes in non-cash working capital	(5.95)	2.05	(390)	9.18	2.76	233
Current income taxes	(6.04)	(4.81)	26	(4.80)	(5.12)	(6)
Income taxes paid	4.49	4.52	(1)	4.82	8.86	(46)
Restricted cash	-	0.99	(100)	-	0.50	(100)
Adjusted funds flow netback (2)	52.54	36.86	43	48.94	41.70	17

(1) Capital management measure. Refer to "Management of capital" in note 12 of the interim financial statements and to "Non-GAAP and Other Financial Measures" within this MD&A.
(2) Non-GAAP ratio. Refer to "Non-GAAP and Other Financial Measures" within this MD&A.

For the three and six months ended June 30, 2026, Headwater's adjusted funds flow netback increased to $52.54 per boe and $48.94 per boe, respectively, from $36.86 per boe and $41.70 per boe in the corresponding periods of the prior year, primarily due to a higher operating netback, including financial derivatives partially offset by higher current income taxes.

Capital Expenditures

	Three months ended June 30, 2026	Three months ended June 30, 2025	Percent Change	Six months ended June 30, 2026	Six months ended June 30, 2025	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Land acquisition, retention and geological and geophysical	25,061	1,371	1,728	30,678	10,418	194
Site preparation	2,970	3,327	(11)	8,192	10,508	(22)
Drilling and completions	43,927	36,770	19	88,582	71,299	24
Equipping and facilities	9,594	9,236	4	20,840	21,326	(2)
Capital expenditures (1)	81,552	50,704	61	148,292	113,551	31

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

During the three months ended June 30, 2026, the Company invested a total of $81.6 million on capital expenditures including $43.9 million on drilling and completions, $25.1 million on land acquisition, retention and geological and geophysical, $9.6 million on equipping and facilities and $3.0 million on site preparation including road construction.

During the six months ended June 30, 2026, the Company invested a total of $148.3 million on capital expenditures including $88.6 million on drilling and completions, $30.7 million on land acquisition, retention and geological and geophysical, $20.8 million on equipping and facilities and $8.2 million on site preparation including road construction.

Drilling Activity

The following table summarizes the Company's drilling results:

	Three months ended June 30, 2026 Gross	2026 Net	2025 Gross	2025 Net	Six months ended June 30, 2026 Gross	2026 Net	2025 Gross	2025 Net
Crude oil	14	14.0	19	19.0	26	26.0	31	30.0
Natural gas	-	-	-	-	-	-	-	-
Injection	21	21.0	7	7.0	31	31.0	11	11.0
Source/stratigraphic test	2	2.0	-	-	14	14.0	4	4.0
Total	37	37.0	26	26.0	71	71.0	46	45.0

(1) Wells included in the above table were rig released during the periods.
(2) One of the previously classified stratigraphic test wells has been reclassified to a crude oil well given it was re-entered during the three months ended June 30, 2026.

Decommissioning Liabilities

As at June 30, 2026, the Company's decommissioning liability was $40.5 million, an increase of $5.3 million from $35.2 million as at December 31, 2025. This increase of $5.3 million is due to additions of $2.8 million, an upward change in estimate of $1.8 million and accretion expense of $0.7 million. The change in estimate is a result of a decrease to the risk-free rate from 3.9% at December 31, 2025 to 3.8% at June 30, 2026, coupled with an increase to the inflation rate from 2.0% at December 31, 2025 to 2.1% at June 30, 2026. The total undiscounted uninflated amount of estimated cash flows required to settle these obligations is $74.7 million (December 31, 2025 – $69.9 million).

2026 Guidance

Headwater is reconfirming the following guidance from April 30, 2026:

	2026 Guidance
Average Daily Production	
Annual (boe/d)	25,000
Pricing	
Crude oil – WTI (US$/bbl)	75.85
Crude oil – WCS (Cdn$/bbl)	83.75
Exchange rate (Cdn$ to US$)	0.73
Natural gas – AGT (US$/mmbtu)	10.90
Financial Summary ($millions)	
Estimated capital expenditures (1)	250
Estimated adjusted funds flow from operations (2)	385
Annual dividend (3)	$0.47/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 12 of the interim 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.

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, supplemented as necessary by equity and debt financings.

During the six months ended June 30, 2026, the Company declared $54.7 million related to its quarterly cash dividend (year ended December 31, 2025 – $104.7 million). The Company increased its quarterly cash dividend to $0.12 per common share, from $0.11 per common share, effective for the dividend paid on July 15, 2026 to shareholders of record at the close of business on June 30, 2026.

As at June 30, 2026, the Company had cash of $87.7 million, adjusted working capital of $9.0 million and no outstanding bank debt. The Company expects to have adequate liquidity to fund its 2026 capital expenditure budget of $250 million, quarterly cash dividends and contractual obligations in the near term through existing working capital and forecasted adjusted funds flow from operations. Headwater anticipates that it will make use of debt or equity financings, as available, for any substantial expansion of its capital program or 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 significant acquisition. Alternatively, the Company may issue equity as consideration to complete any future acquisition.

On May 11, 2026, Headwater announced that it received TSX approval for the renewal of its normal course issuer bid (“NCIB”). The renewed NCIB allows Headwater to purchase for cancellation up to 22,287,602 common shares during the one-year period commencing on May 13, 2026. During the three and six months ended June 30, 2026, Headwater did not purchase any common shares under its NCIB.

Credit Facilities

The Company has senior secured revolving syndicated 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 June 30, 2026, Headwater had not drawn on the credit facilities.

The credit facilities have a revolving period of two years, extendible annually at the request of the Company, subject to approval of the Lenders. The next scheduled borrowing base redetermination is to occur by May 31, 2027. The credit facilities are secured by a demand debenture in the amount of $500 million. Principal repayments are not required until the maturity date, provided that the borrowings under the credit facilities 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

As at June 30, 2026, the Company is committed to future payments under the following agreements:

(thousands)	Total	2026	2027	2028	2029	2030	Thereafter
	$	$	$	$	$	$	$
Transportation and operating	217,989	14,753	33,045	32,748	31,598	23,673	82,172
Lease (1)	1,417	224	455	463	275	-	-
Government grant (2)	8,034	-	8,034	-	-	-	-

(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 Natural Resources Canada.
(3) Excludes leases accounted for under IFRS 16.

Common Share Information

Share Capital

	Three months ended June 30,		Six months ended June 30,	
	2026	2025	2026	2025
	(thousands)		*(thousands)*	
Weighted average outstanding common shares (1)				
-Basic	237,763	237,763	237,763	237,767
-Diluted	240,052	239,471	239,897	239,469
Outstanding securities at June 30, 2026 *(thousands)*				
-Common shares				237,763
-Restricted share units				372
-Performance share units				3,444
-Deferred share units				445

(1) The Company uses the treasury stock method to determine the dilutive effect of 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.

Total Market Capitalization

The Company's market capitalization at June 30, 2026 was approximately $2.8 billion.

(thousands)	June 30, 2026
Common shares outstanding	237,763
Share price (1)	11.83
Total market capitalization	2,812,736

(1) Represents the closing price of the common shares on the TSX on June 30, 2026.

As at July 23, 2026, the Company had 237,762,877 common shares outstanding.

(thousands)	July 23, 2026
Outstanding securities at July 23, 2026	
-Common shares	237,763
-Restricted share units	372
-Performance share units	3,444
-Deferred share units	445

Environmental, Social and Governance Update

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

- At the Company's annual meeting of shareholders held on May 20, 2026, 33% of Headwater's directors elected to the Board were women and as a result, Headwater continues to meet its Board diversity commitment of women representing 30% or more of the members of the Board.

- 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, or $1.4 million, on June 30, 2025 and 33% of the balance, or $4.7 million, on June 30, 2026. The remaining repayable portion of the funds, representing 57% of the balance, is to be repaid 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 April 2, 2026, for the annual meeting of the shareholders held on May 20, 2026, 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.

Summary of Quarterly Information

	Q2/26	Q1/26	Q4/25	Q3/25	Q2/25	Q1/25	Q4/24	Q3/24
Financial *(thousands of dollars except share data)*								
Total sales	237,928	176,721	151,080	152,101	144,944	170,155	163,107	158,382
Total sales, net of blending expense (1) (2)	227,666	169,905	145,308	146,511	138,808	163,188	156,475	151,740
Adjusted funds flow from operations (3)	117,749	97,359	79,254	80,394	74,218	92,359	87,903	84,185
Per share - basic	0.50	0.41	0.33	0.34	0.31	0.39	0.37	0.35
- diluted	0.49	0.41	0.33	0.33	0.31	0.39	0.37	0.35
Cash flows provided by operating activities	134,566	40,069	72,668	85,861	68,673	69,935	76,016	95,272
Net income	85,416	35,567	29,311	35,869	38,023	50,004	48,907	47,634
Per share - basic (4)	0.36	0.15	0.12	0.15	0.16	0.21	0.21	0.20
- diluted (4)	0.36	0.15	0.12	0.15	0.16	0.21	0.21	0.20
Capital expenditures (2)	81,552	66,740	46,066	68,671	50,704	62,847	48,686	58,196
Depletion and depreciation	29,720	28,945	29,438	32,448	32,636	32,515	31,382	32,015
Adjusted working capital (3)	9,018	2,439	23,581	36,444	58,472	63,616	67,578	64,411
Working capital	10,199	(3,028)	29,951	41,767	64,836	72,107	78,735	74,925
Shareholders' equity	814,452	757,568	748,155	752,377	735,055	723,431	699,459	684,486
Dividends declared	28,532	26,154	26,154	26,264	26,155	26,155	23,776	23,767
Per share	0.12	0.11	0.11	0.11	0.11	0.11	0.10	0.10
Weighted average shares (thousands)								
Basic	237,763	237,763	238,142	237,828	237,763	237,772	237,512	237,484
Diluted (5)	240,052	239,366	240,647	240,026	239,471	237,813	237,569	239,735
Shares outstanding, end of period (thousands)								
Basic	237,763	237,763	237,763	238,763	237,763	237,774	237,757	237,665
Diluted (6)	237,763	237,763	237,763	238,763	237,763	237,904	237,934	241,115
Operating ***(6:1 boe conversion)***								
Average daily production								
Heavy oil (*bbls/d*)	23,046	21,857	22,091	20,948	20,249	19,511	20,304	19,718
Natural gas *(mmcf/d)*	8.2	13.0	12.1	8.4	10.8	14.5	7.2	3.4
Natural gas liquids *(bbls/d)*	148	135	143	169	185	142	51	64
Barrels of oil equivalent *(boe/d)* (7)	24,567	24,154	24,259	22,523	22,235	22,066	21,559	20,342
Average daily sales (8)	24,627	23,930	24,166	22,699	22,123	22,019	21,543	20,329
Average selling prices								
Heavy oil (*$/bbl*)	106.71	78.64	66.34	74.66	73.75	83.76	80.26	83.35
Natural gas *($/mcf)*	2.13	13.10	8.82	0.28	2.22	11.22	8.91	0.25
Natural gas liquids *($/bbl)*	104.11	73.83	64.29	71.28	70.38	80.82	77.84	79.95
Barrels of oil equivalent *($/boe)*	101.45	78.61	65.20	70.12	68.80	81.94	78.76	81.09
Netbacks *($/boe)* (9)								
Operating								
Total sales, net of blending expense (1) (2)	101.59	78.89	65.35	70.16	68.95	82.35	78.95	81.13
Realized gain (loss) on financial derivatives	(5.29)	(2.54)	(1.12)	(0.06)	(0.36)	(1.60)	(0.35)	0.18
Royalties	(22.09)	(12.46)	(10.29)	(12.74)	(12.84)	(14.47)	(13.81)	(15.74)
Transportation	(6.06)	(5.79)	(5.59)	(5.68)	(5.65)	(5.41)	(5.26)	(5.90)
Production	(8.27)	(8.20)	(7.21)	(7.01)	(7.44)	(7.93)	(7.64)	(7.46)
Operating netback, including financial derivatives *($/boe)* (4)	59.88	49.90	41.14	44.67	42.66	52.94	51.89	52.21
General and administrative expense	(1.51)	(1.47)	(1.57)	(1.51)	(1.44)	(1.44)	(1.53)	(1.42)
Interest income and other expense (10)	0.21	0.27	0.31	0.40	0.45	0.59	0.60	0.76
Current income tax expense	(6.04)	(3.50)	(4.13)	(5.07)	(4.81)	(5.43)	(6.62)	(6.54)
Settlement of decommissioning liability	-	-	(0.10)	-	-	(0.05)	-	-
Adjusted funds flow netback *($/boe)* (4)	52.54	45.20	35.65	38.49	36.86	46.61	44.34	45.01

(1) Heavy oil sales are netted with blending expense to compare the realized price to benchmark. In the interim 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 12 of the interim financial statements and to “Non-GAAP and Other Financial Measures” within this MD&A.
(4) Non-GAAP ratio. Refer to “Non-GAAP and Other Financial Measures” within this MD&A.
(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 June 30, 2026, all outstanding stock options have been exercised.
(6) RSUs and PSUs have been excluded as the Company intends to cash settle these awards. As of June 30, 2026, 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.
(10) Excludes unrealized foreign exchange gains/losses, accretion on decommissioning liabilities, interest on repayable contribution and interest on the lease liability.

Headwater has experienced substantial quarterly growth over the past two years as a result of its significant capital expenditure programs. The Company has grown production from 20,342 boe/d in the third quarter of 2024 to 24,567 boe/d in the second quarter of 2026, representing a 21% increase. This production growth is attributed to successful drilling and secondary recovery results in the Company’s main development area of Marten Hills, as well as discoveries in newer areas including Greater Pelican. During the three months ended June 30, 2026, heightened geopolitical tensions in the Middle East lifted WTI to US$92.79/bbl, contributing to record adjusted funds flow from operations of $117.7 million, funding capital expenditures of $81.6 million and Headwater’s quarterly dividend of $0.12 per common share. Headwater’s continued focus on secondary recovery has lowered maintenance capital requirements and corporate decline rates, contributing to free cash flow generation and expansion of the Company’s return of capital strategy. The Company increased its quarterly cash dividend to $0.12 per common share, from $0.11 per common share, effective for the dividend paid on July 15, 2026 to shareholders of record at the close of business on June 30, 2026.

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 June 30, 2026, the Company declared a cash dividend of $0.12 per common share. The dividend will be paid on October 15, 2026, to shareholders of record at the close of business on September 30, 2026.The dividend will be an eligible dividend for purposes of the *Income Tax Act* (Canada).

b) Financial derivative commodity contract

Subsequent to June 30, 2026, Headwater entered into the following financial derivative contract:

Commodity	Index	Type	Term	Daily Volume	Contract Price
Natural Gas	AGT	Fixed	Dec 2026 – Jan 2027	1,000 mmbtu	Cdn$25.00/mmbtu

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 interim financial statements blending expense is recorded within blending and transportation expense.

	Three months ended June 30,		Six months ended June 30,	
	2026	2025	2026	2025
	(thousands of dollars)		*(thousands of dollars)*	
Heavy oil sales	234,629	141,282	394,552	294,966
Blending expense	(10,262)	(6,136)	(17,078)	(13,103)
Heavy oil sales, net of blending expense	224,367	135,146	377,474	281,863

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 interim financial statements blending expense is recorded within blending and transportation expense.

	Three months ended June 30,		Six months ended June 30,	
	2026	2025	2026	2025
	(thousands of dollars)		*(thousands of dollars)*	
Total sales	237,928	144,944	414,649	315,099
Blending expense	(10,262)	(6,136)	(17,078)	(13,103)
Total sales, net of blending expense	227,666	138,808	397,571	301,996

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 interim financial statements.

	Three months ended June 30,		Six months ended June 30,	
	2026	2025	2026	2025
	(thousands of dollars)		*(thousands of dollars)*	
Cash flows used in investing activities	78,784	40,781	129,016	103,884
Change in non-cash working capital	2,768	9,923	19,276	9,667
Capital expenditures	81,552	50,704	148,292	113,551

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 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 June 30,		Six months ended June 30,	
	2026	2025	2026	2025
	(thousands of dollars)		*(thousands of dollars)*	
Cash flows provided by operating activities	134,566	68,673	174,635	138,608
Changes in non-cash working capital	(13,331)	4,122	40,353	11,010
Current income taxes	(13,541)	(9,683)	(21,080)	(20,453)
Income taxes paid	10,055	9,106	21,200	35,412
Restricted cash	-	2,000	-	2,000
Adjusted funds flow from operations	117,749	74,218	215,108	166,577

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.

	As at June 30, 2026	As at December 31, 2025
	(thousands of dollars)	
Working capital	10,199	29,951
Repayable contribution	-	(7,202)
Financial derivative receivable	(1,397)	(393)
Financial derivative liability	216	1,225
Adjusted working capital	9,018	23,581

<u>Non-GAAP Ratios</u>

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 plus realized gains (losses) on financial derivatives.

Adjusted funds flow per share

Adjusted funds flow 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 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

The corporate 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.

Supplementary Financial Measures

Per boe numbers

This MD&A presents various results on a per boe basis including 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, total 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, exploration and evaluation expense per boe, current income tax expense per boe, deferred income tax expense per boe, total income tax expense per boe, cash flows provided by operating activities per boe, changes in non-cash working capital per boe, settlement of decommissioning liabilities per boe, and net income per boe. These figures are calculated using sales volumes.

Disclosure Controls and Procedures

The Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures as defined in National Instrument 52-109 – *Certification of Disclosures in Issuers' Annual and Interim Filings* of the Canadian Securities Administrators, to provide reasonable assurance that (i) material information relating to the Company is made known to the Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual and interim filings are being prepared 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.

Internal Controls over Financial Reporting

The Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal controls over financial reporting as defined in National Instrument 52-109 of the Canadian Securities Administrators, in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

The Company confirms that there were no changes to Headwater's internal controls over financial reporting during the interim period from April 1, 2026 to June 30, 2026 that have materially affected, or are reasonably likely to affect, the Company's internal control over financial reporting.

It should be noted that while Headwater's Chief Executive Officer and Chief Financial Officer believe that the Company's internal controls and procedures provide a reasonable level of assurance and that they are effective, they do not expect that 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, the United States–Israel–Iran war (and other Middle Eastern conflicts) 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 USMCA (all of the Company's energy products currently qualify under the USMCA). On July 1, 2026, the parties completed the mandatory joint review of USMCA. While the United States did not agree to extend USMCA in its current form, the agreement remains in force and the parties are expected to continue discussions regarding potential amendments and future renewal of the agreement. Until the USMCA is renewed, any of the countries can withdraw from the agreement on six months notice. As a result, uncertainty remains regarding the future terms governing North American trade and in respect of Canadian exports (including energy products) to the United States. These dynamics influence export costs, market access, and demand for Canadian energy products. Significant changes to USMCA, the failure of the parties to ultimately agree to an extension of the agreement or the withdrawal of a party from the agreement 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 interim financial statements as at and for the three and six months ended June 30, 2026. 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 June 30, 2026, and climate risk/climate change, in and 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 have been made under the Company’s insurance policies in 2026 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 PSUs

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

New accounting policies

During the six months ended June 30, 2026, the Company adopted amendments to IFRS 9 "Financial Instruments" and IFRS 7 "Financial Instruments: Disclosures". These amendments clarify the date of recognition and derecognition of some financial assets and liabilities. These amendments did not have a material impact on the Company's financial statements.

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.

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) following the July 1, 2026 USMCA joint review, the parties are unable to agree on future amendments to or an extension of USMCA, or a party ultimately withdraws from USMCA, 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 U.S.–Israel–Iran war (and other Middle East conflicts) 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 (including forest fires in the areas where the Company operates), 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 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 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
- Implementation of cyber security protocols and procedures to reduce the risk of failure of breach of data.

Oil and Gas Metrics

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 return of capital policy from time to time and, as a result, future cash dividends could be reduced or suspended entirely.

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 estimated value of the Company's derivative contracts;

- the possibility that the Company may mitigate a portion of its risk by entering into foreign exchange contracts;
- expectations with respect to the construction of the oil transportation pipeline in Marten Hills, the expected timing of commissioning and the anticipated benefits and results therefrom, including that Headwater will realize more than $20 million per year, or $2.00 per boe, in transportation/operating cost savings;
- 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;
- that directors may also elect to receive all of their annual cash compensation in the form of DSUs subject to certain conditions;
- the estimated undiscounted uninflated amount of cash flows required to settle the Company's decommissioning liabilities;
- 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, future dividend payments and contractual obligations 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; that developments arising from the July 1, 2026 USMCA joint review, including any amendments to, extension of, or withdrawal from USMCA, do not significantly impact the ability or costs of Canadian oil and gas companies to export their products into the United States or have other negative to the Canadian economy and/or the Company's business; 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 25,000 boe/d, WTI of US$75.85/bbl, WCS of Cdn$83.75/bbl, AGT US$10.90/mmbtu, AECO of $1.65 CAD/GJ, foreign exchange rate of US$/Cdn$ of 0.73, blending expense of WCS less $1.10, royalty rate of 20.2%, operating and transportation costs of $14.15/boe, G&A and interest expense of $1.60/boe and cash taxes of $4.50/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: 23,180 bbls/d of heavy oil, 120 bbls/d of natural gas liquids and 10.2 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 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 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

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