2021 Management's Discussion and Analysis

The following management's discussion and analysis ("MD&A") as provided by the management of Headwater Exploration Inc. ("Headwater" or the "Company") is dated March 10, 2022 and should be read in conjunction with the audited annual financial statements for the years ended December 31, 2021 and 2020 and the notes thereto. The audited annual financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). All dollar amounts are referenced in Canadian dollars unless otherwise stated. In addition, readers are also directed to the Company's Annual Information Form for the year ended December 31, 2021, dated March 10, 2022, which is available on the Company's website at www.headwaterexp.com and under the Company's profile on the System for Electronic Document Analysis and Retrieval ("SEDAR") at www.sedar.com.

Description of the Company

Headwater is a Canadian junior resource company engaged in the exploration for and development and production of petroleum and natural gas in Canada. Headwater currently has heavy oil production and reserves in the Clearwater formation in the Marten Hills area of Alberta and natural gas production and reserves in the McCully field near Sussex, New Brunswick.

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

FOURTH QUARTER 2021 HIGHLIGHTS

- Achieved average production of 10,449 boe/d (consisting of 9,377 bbls/d of heavy oil and 6.4 mmcf/d of natural gas), an increase of over 500% from the fourth quarter of 2020.
- Cash flows provided by operating activities was $47.8 million, $0.23 per share (basic), and adjusted funds flow from operations (1) was $48.7 million, $0.24 per share (basic).
- Achieved an operating netback (2) of $50.36/boe and an adjusted funds flow netback (2) of $50.64/boe.
- Generated net income of $27.9 million, $0.14 per share (basic), and adjusted net income (3) of $32.6 million, $0.16 per share (basic).
- Executed a $49.0 million capital expenditure (3) program in the Marten Hills area including 3 successful exploration wells and 8 multi-lateral development wells at a 100% success rate. In addition to the drilling program, $26.5 million was spent on equipping and facilities primarily for ongoing construction of Headwater's 100% owned 15,000 bbls/d oil processing facility. The oil processing facility was commissioned subsequent to December 31, 2021.
- On December 23, 2021, Cenovus Marten Hills Partnership, a wholly owned subsidiary of Cenovus Energy Inc. ("Cenovus"), exercised its 15 million warrants (the "Cenovus Warrants") for 15 million common shares of the Company for total proceeds of $30 million. On exercise of the Cenovus Warrants, Cenovus held approximately 7% of the outstanding common shares of the Company.
- As at December 31, 2021, Headwater had working capital of $89.8 million, adjusted working capital (1) of $92.9 million and no outstanding debt.

YEAR ENDED DECEMBER 31, 2021 HIGHLIGHTS

- Achieved average production of 7,393 boe/d (consisting of 6,665 bbls/d of heavy oil, 4.4 mmcf/d of natural gas and 2 bbls/d of natural gas liquids), an increase of over 700% from 2020 annual production of 882 boe/d.

- Cash flows provided by operating activities was $111.7 million, $0.56 per share (basic), and adjusted funds flow from operations (1) was $117.9 million, $0.59 per share (basic).

- Executed a $140.4 million capital expenditure (3) program in the Marten Hills area including 58 wells (51 crude oil wells, 4 source wells and 3 stratigraphic tests) at 100% success rate.

- The Company's joint gas processing facility, commissioned in the third quarter of 2021, in combination with pipeline infrastructure installed in the first quarter of 2021, has resulted in an approximate 50% reduction in Headwater's CO2e emissions intensity per barrel of oil equivalent over the 2021 calendar year.

(1) Refer to "Management of capital" in note 18 of the audited annual financial statements and to "Non-GAAP and Other Financial Measures" within this MD&A.
(2) Non-GAAP ratio that does not have any standardized meaning under IFRS and therefore may not be comparable with the calculation of similar measures of other entities. Refer to "Non-GAAP and Other Financial Measures" within this MD&A.
(3) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable with the calculation of similar measures of other entities. The most directly comparable GAAP measure for adjusted net income is net income. Refer to "Non-GAAP and Other Financial Measures" within this MD&A.

Results of Operations

Production and Pricing

	Three months ended December 31, 2021	Three months ended December 31, 2020	Percent Change	Year ended December 31, 2021	Year ended December 31, 2020	Percent Change
Average daily production						
Heavy oil (bbls/d)	9,377	979	858	6,665	246	2609
Natural gas (mmcf/d)	6.4	4.0	60	4.4	3.8	16
Natural gas liquids (bbls/d)	-	3	(100)	2	3	(33)
Barrels of oil equivalent (boe/d)	10,449	1,646	535	7,393	882	738
Average daily sales (boe/d) (1)						
Heavy oil (bbls/d)	9,388	979	859	6,661	246	2608
Natural gas (mmcf/d)	6.4	4.0	60	4.4	3.8	16
Natural gas liquids (bbls/d)	-	3	(100)	2	3	(33)
Barrels of oil equivalent (boe/d)	10,459	1,646	535	7,390	882	738
Headwater average sales price (2)						
Heavy oil ($/bbl) (3)	75.12	45.05	67	68.69	45.05	52
Natural gas ($/mcf)	8.46	5.37	58	7.18	3.21	124
Natural gas liquids ($/bbl)	-	56.23	(100)	70.14	57.28	22
Barrels of oil equivalent ($/boe)	72.62	39.90	82	66.18	26.57	149
Average Benchmark Price						
WTI (US$/bbl) (4)	77.19	42.66	81	67.91	39.40	72
WCS differential to WTI (US$/bbl)	(14.64)	(9.30)	57	(13.04)	(12.60)	3
WCS (Cdn$/bbl) (5)	78.72	43.42	81	68.73	35.59	93
Condensate at Edmonton (Cdn$/bbl)	99.65	55.37	80	85.47	49.45	73
AGT (US$/mmbtu) (6)	8.09	3.23	150	5.49	2.47	122
AECO 5A (Cdn$/GJ)	4.41	2.50	76	3.44	2.11	63
NYMEX Henry Hub (US$/mmbtu)	5.83	2.66	119	3.84	2.08	85
Exchange rate (US$/Cdn$)	0.79	0.77	3	0.80	0.75	7

(1) Includes sales of heavy crude oil excluding the impact of purchased condensate. The Company's heavy oil sales volumes and production volumes differ due to changes in inventory.
(2) Average sales prices are calculated using average sales volumes.
(3) Realized heavy oil prices are based on sales, net of blending expense.
(4) WTI = West Texas Intermediate
(5) WCS = Western Canadian Select
(6) AGT = Algonquin city-gates. The AGT price is the average for the winter producing months in the McCully field which include January – April, November and December.

Sales

	Three months ended December 31, 2021	Three months ended December 31, 2020	Percent Change	Year ended December 31, 2021	Year ended December 31, 2020	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Heavy oil sales	70,038	4,400	1492	178,434	4,400	3955
Blending expense	(5,162)	(343)	1405	(11,423)	(343)	3230
Heavy oil, net of blending (1)	64,876	4,057	1499	167,011	4,057	4017
Natural gas	5,005	1,966	155	11,416	4,466	156
Natural gas liquids	-	17	(100)	62	54	15
Gathering, processing and transportation	244	243	-	1,028	579	78
Total sales, net of blending expense (1)	70,125	6,283	1016	179,517	9,156	1861

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

Marten Hills

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.

During the year ended December 31, 2021, Headwater's heavy oil sales, net of blending expense, increased to $167.0 million from $4.1 million in 2020 due to a significant increase in both sales volumes and realized prices.

In 2021, the WTI crude price strengthened significantly as a result of increased demand for crude oil following the global recovery from the COVID-19 pandemic. The WCS differential to WTI remained narrow due to improved market access out of western Canada. The Company's heavy oil realized price for the year ended December 31, 2021, was $68.69/bbl, reflecting a discount to WCS of $0.04/bbl. The negligible discount to WCS realized over the year ended December 31, 2021, is a result of the Company selling more volumes later in the year at higher commodity pricing. Pursuant to the Acquisition (as defined below), Headwater acquired Cenovus' Marten Hills assets with approximately 2,800 bbls/d of heavy crude oil production in December 2020 and commenced its drilling program in January 2021. The Company averaged 2021 production volumes of 6,665 bbls/d and sales volumes of 6,661 bbls/d.

During the three months ended December 31, 2021, Headwater's heavy oil sales, net of blending expense, increased to $64.9 million from $4.1 million in the comparable period of 2020 due to an 859% increase in sales volumes and a 67% increase in realized prices. The Company's heavy oil realized price for the three months ended December 31, 2021, was $75.12/bbl, reflecting a discount to WCS of $3.60/bbl mainly resulting from increased blending costs, apportionment and terminal outages. The cost of condensate increased significantly to $99.65/bbl in the fourth quarter of 2021 from $55.37/bbl in the fourth quarter of 2020 resulting in increased blending costs.

The Company expects the weighted average annual discount to WCS, as a result of diluent blending, to be approximately $2.50/bbl in 2022.

The Company commissioned its Marten Hills joint gas processing facility and started generating sales from its associated natural gas production in the third quarter of 2021. The natural gas sales transaction price is based on the AECO 5A daily benchmark price adjusted for delivery location and heat content. Headwater's natural gas sales volumes averaged 2.5 mmcf/d with natural gas sales of $1.0 million during the three months ended December 31, 2021, while its natural gas sales volumes averaged 0.7 mmcf/d with natural gas sales of $1.1 million during the year ended December 31, 2021.

McCully

The Company sells its natural gas production daily from the McCully field in New Brunswick. The transaction price is based on the AGT daily benchmark price adjusted for the delivery location and heat content. The Company shut-in production effective May 1, 2021, and May 1, 2020, to take advantage of higher natural gas pricing during the winter months. The Company resumed operations at the end of November 2021 and at the end of October 2020.

Natural gas sales for the three months ended December 31, 2021, increased to $4.0 million from $2.0 million in the corresponding period of 2020, due primarily to a 109% increase in Headwater's average realized natural gas sales price as production remained consistent over the periods at 3.9 mmcf/d during the three months ended December 31, 2021, compared to 4.0 mmcf/d during the three months ended December 31, 2020. The increase in Headwater's average realized natural gas sales price was consistent with the increase in the AGT benchmark over the period.

Natural gas sales for the year ended December 31, 2021, increased to $10.3 million from $4.5 million in the corresponding period of 2020, due primarily to a 142% increase in Headwater's average realized natural gas sales price as production remained consistent over the periods at 3.7 mmcf/d during the twelve months ended December 31, 2021, compared to 3.8 mmcf/d during the twelve months ended December 31, 2020. The increase in Headwater's average realized natural gas sales price was consistent with the increase in the AGT benchmark price over the period.

In 2021, AGT benchmark pricing increased as a result of lower than average natural gas storage levels and colder North American east coast temperatures as compared to 2020.

Headwater owns the midstream facilities which process and transport gas from the McCully field to the Maritimes & Northeast Pipeline ("M&NP"). Gathering, processing and transportation revenue primarily relates to income earned on third party gas flowing through these facilities. This revenue will vary quarter over quarter depending on the amount of third-party volumes processed.

Financial Derivatives Gains (Losses)

	Three months ended December 31,		Percent Change	Year ended December 31,		Percent Change
	2021	2020		2021	2020	
	(thousands of dollars)			*(thousands of dollars)*		
Realized financial derivative gains	1,360	1,578	(14)	955	5,515	(83)
Unrealized financial derivative gains (losses)	5,830	205	2744	(3,228)	(1,407)	129
Financial derivative gains (losses)	7,190	1,783	303	(2,273)	4,108	(155)
Per boe	7.47	11.77	(37)	(0.84)	12.73	(107)

Natural gas and crude oil commodity contracts

The realized financial derivative gains and losses during the three and twelve months ended December 31, 2021, represent both the natural gas contracts referenced to the AGT price and the crude oil contracts referenced to the WCS price.

A realized financial derivative gain was recorded during the three and twelve months ended December 31, 2021 of $1.0 million and $0.6 million, respectively, compared to a realized gain of $1.6 million and $5.5 million in the same periods of 2020 for the Company's natural gas contracts settled. The Company recognized gains on its natural gas contracts in 2021 as the commodity contracts to fix the AGT price were higher when compared to the AGT settlement price in the period. North American east coast temperatures and natural gas storage levels are the main variables impacting the AGT settlement price.

A realized financial derivative gain of $0.4 million was recorded for both the three and twelve months ended December 31, 2021, for the Company's oil contracts settled. The Company recognized gains on its oil contracts in 2021 as the commodity contracts to fix the WCS price were higher when compared to the WCS settlement price in the period. US Gulf Coast heavy oil demand and market access are the main variables impacting the WCS settlement price.

As at December 31, 2021, the fair value of Headwater's outstanding financial derivative contracts was a net unrealized liability of $3.2 million as reflected in the audited annual 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 December 31, 2021, had the contracts been monetized or terminated. Subsequent changes in the fair value of the contracts are recognized in each reporting period and could be materially different than what is recorded as at December 31, 2021. For the three and twelve months ended December 31, 2021, Headwater recognized unrealized gains of $5.8 million and unrealized losses of $3.2 million, respectively, compared to unrealized gains of $0.2 million and unrealized losses of $1.4 million in the corresponding periods of 2020.

As at December 31, 2021, Headwater had the following financial derivative commodity contracts outstanding:

Commodity	Index	Type	Term	Daily Volume	Contract Price
Natural Gas	AGT Basis (1)	Differential	Jan 1- Feb 28, 2022	2,500 mmbtu	Cdn$7.26/mmbtu
Natural Gas	AGT Basis (2)	Differential	Jan 1- Mar 31, 2022	2,500 mmbtu	Cdn$4.16/mmbtu
Natural Gas	NYMEX	Fixed	Jan 1- Feb 28, 2022	2,500 mmbtu	Cdn$3.85/mmbtu
Natural Gas	NYMEX	Fixed	Jan 1- Mar 31, 2022	2,500 mmbtu	Cdn$3.76/mmbtu
Natural Gas	AGT	Fixed	Jan 2022	2,500 mmbtu	Cdn$20.89/mmbtu
Natural Gas	AGT	Fixed	Jan 1- Feb 28, 2022	2,500 mmbtu	Cdn$25.27/mmbtu
Natural Gas	AGT	Fixed	Mar 2022	2,500 mmbtu	Cdn$11.07/mmbtu

(1) Headwater pays on AGT while counterparty pays on NYMEX plus Cdn$7.26/mmbtu
(2) Headwater pays on AGT while counterparty pays on NYMEX plus Cdn$4.16/mmbtu

Foreign exchange contracts

The Company is exposed to fluctuations of 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 heavy oil and natural gas marketing arrangements.

Headwater mitigates this risk by entering into commodity contracts in Canadian dollars and entering into short-term foreign exchange contracts.

As at December 31, 2021, Headwater had the following financial derivative foreign exchange contract outstanding:

Type	Buy Currency	Sell Currency	Rate	Notional Amount	Settlement Date
Forward contract	CAD	USD	WMR noon rate, December 2021 average (1)	US$17,000,000	January 25, 2022

(1) WM/Reuters Intraday Spot Rate as of Noon EST

Subsequent to December 31, 2021, the Company entered into additional natural gas commodity contracts and foreign exchange contracts. Refer to the heading “Subsequent Events”.

Royalty Expense

	Three months ended December 31, 2021	Three months ended December 31, 2020	Percent Change	Year ended December 31, 2021	Year ended December 31, 2020	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Heavy oil	10,643	541	1867	25,414	541	4598
Natural gas and natural gas liquids	266	43	519	524	115	356
Total royalty expense	10,909	584	1768	25,938	656	3854
Percentage of total sales, net of blending (1)	15.6%	9.3%	68	14.4%	7.2%	100
Per boe ($)	11.34	3.86	194	9.62	2.03	374

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

Royalty expense consists of crown royalties payable to the Alberta and New Brunswick provincial governments and the gross overriding royalty ("GORR") payable to Topaz Energy Corp. (Topaz Energy Corp. acquired the GORR from Cenovus in May 2021). Under the Alberta Modernized Royalty Framework ("MRF"), 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 (C*), then royalty rates increase on a sliding scale up to 40% depending on commodity reference pricing.

For the three and twelve months ended December 31, 2021, royalty expense increased to $10.9 million and $25.9 million, respectively, from $0.6 million and $0.7 million in the same periods of the prior year because of royalties incurred related to the Company's Marten Hills assets acquired in December 2020.

Headwater's average corporate royalty rate was 15.6% for the fourth quarter of 2021 and 14.4% for the year ended December 31, 2021, compared to 9.3% and 7.2% in the comparable periods of 2020, respectively, reflecting crown and GORR royalties incurred on the Company's Marten Hills assets acquired in December 2020. The increase in Headwater's average corporate royalty rate throughout 2021 is due to a significant increase in both Headwater's cumulative heavy oil production and realized heavy oil sales price. Over the course of 2021, several of the Company's Marten Hills wells' cumulative revenues exceeded C* and reverted to the sliding scale royalty under the MRF, resulting in a higher Alberta crown royalty rate.

Transportation Expense

	Three months ended December 31,		Percent	Year ended December 31,		Percent
	2021	2020	Change	2021	2020	Change
	(thousands of dollars)			*(thousands of dollars)*		
Transportation expense	6,719	772	770	20,355	772	2537
Per boe ($)	6.98	5.10	37	7.55	2.40	215

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

For the three and twelve months ended December 31, 2021, transportation expense increased to $6.7 million and $20.4 million, respectively, from $0.8 million in the same periods of the prior year as a result of transportation costs incurred related to the Company's Marten Hills assets acquired in December 2020.

Headwater's transportation expense was $6.98 per boe during the fourth quarter of 2021 down from $8.68 per boe during the third quarter of 2021 as a result of additional production volumes from the Company's McCully assets which were shut-in over the summer.

Following commissioning of Headwater's 15,000 bbls/d oil processing facility subsequent to December 31, 2021, transportation costs have decreased by approximately $4.00/boe, from $7.55/boe in the year ended December 31, 2021, due to lower trucking and terminal fees.

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

Production Expense

	Three months ended December 31, 2021	2020	Percent Change	Year ended December 31, 2021	2020	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Production expense	4,041	1,199	237	12,513	2,899	332
Per boe ($)	4.20	7.92	(47)	4.64	8.98	(48)

Production expenses in the three and twelve months ended December 31, 2021, were $4.0 million and $12.5 million, respectively, compared to $1.2 million and $2.9 million in the corresponding periods of 2020. The increase in production expense reflects production expense incurred related to the Company's Marten Hills assets acquired in December 2020.

Production expenses per boe averaged $4.20 per boe and $4.64 per boe during the three and twelve months ended December 31, 2021. Production expenses per boe decreased during the three and twelve months December 31, 2021, when compared to the corresponding periods of 2020, due to the integration of the Marten Hills assets which carry lower costs per boe than Headwater's historical average.

Headwater's production expense decreased to $4.20 per boe in the fourth quarter of 2021, down from $4.42 per boe in the third quarter of 2021, $4.89 per boe in the second quarter of 2021 and $5.62 per boe in the first quarter of 2021 due primarily to lower water handling and disposal costs and increased production volumes offsetting fixed production expenses with respect to the Company's heavy oil production.

Netbacks

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

	Three months ended December 31, 2021	2020	Percent Change	Year ended December 31, 2021	2020	Percent Change
	($/boe)			*($/boe)*		
Sales	78.25	43.77	79	70.80	29.43	141
Royalties	(11.34)	(3.86)	194	(9.62)	(2.03)	374
Transportation and blending	(12.35)	(7.37)	68	(11.78)	(3.46)	240
Production expense	(4.20)	(7.92)	(47)	(4.64)	(8.98)	(48)
Operating netback (1)	50.36	24.62	105	44.76	14.96	199
Realized gains on financial derivatives	1.41	10.42	(86)	0.35	17.09	(98)
Operating netback, including financial derivatives (1)	51.77	35.04	48	45.11	32.05	41

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

General and Administrative ("G&A") Expenses

	Three months ended December 31, 2021	2020	Percent Change	Year ended December 31, 2021	2020	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Gross G&A expenses	2,244	742	202	7,135	2,915	145
Overhead recoveries & capitalized G&A	(1,064)	(39)	2628	(3,154)	(80)	3843
Net G&A expenses	1,180	703	68	3,981	2,835	40
Per boe ($)	1.23	4.64	(73)	1.48	8.78	(83)

The Company incurred gross G&A expenses of $2.2 million and $7.1 million, respectively, during the three and twelve months ended December 31, 2021, compared to $0.7 million and $2.9 million in the corresponding periods of 2020. Increased G&A costs before recoveries and capitalization were mainly the result of a larger workforce to accommodate Headwater's Marten Hills assets and include increased employee related costs, software fees and professional fees. Headwater recognized overhead recoveries and capitalized G&A of $1.1 million and $3.2 million, respectively, during the three and twelve months ended December 31, 2021 as a result of the Company's significant capital expenditure program.

G&A expenses for the three and twelve months ended December 31, 2021, were $1.23 per boe and $1.48 per boe, respectively, compared to $4.64 per boe and $8.78 per boe in the corresponding periods of 2020. The decrease in G&A expenses per boe is a result of a significant increase in sales volumes from the Marten Hills assets acquired in December 2020.

Interest Income and Other Expense

	Three months ended December 31, 2021	2020	Percent Change	Year ended December 31, 2021	2020	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Interest income	159	236	(33)	663	1,144	(42)
Foreign exchange gains (losses)	(65)	(24)	171	(432)	129	(435)
Accretion on decommissioning liability	(110)	(32)	244	(341)	(149)	129
Interest on lease liability	(13)	-	100	(35)	(11)	218
Total interest income and other expense	(29)	180	(116)	(145)	1,113	(113)
Per boe ($)	(0.03)	1.19	(103)	(0.05)	3.45	(101)

Interest income and other expense decreased in both the three and twelve months ended December 31, 2021, primarily as a result of lower interest income and an increase in realized foreign exchange losses.

Interest income decreased in both the three and twelve months ended December 31, 2021, compared to the same periods in the prior year, due to a lower average cash balance on hand in 2021 and a lower interest rate earned in 2021 when compared to 2020. The Bank of Canada dropped its overnight interest rate by 150 basis points from 1.75% to 0.25% in March 2020, as a response to economic uncertainty due to the COVID-19 pandemic. Additionally, the Company's $15 million guaranteed investment certificate was redeemed on April 1, 2021, at a maturity rate of 1.65%.

Realized foreign exchange gains and losses will vary depending on the fluctuation in the exchange rate between the timing of sales incurred which are denominated in US dollars and the timing of the settlement of the underlying receivable. The Company realized foreign exchange losses of $0.1 million in the three months ended December 31, 2021, and foreign exchange losses of $0.4 million in the twelve months ended December 31, 2021. The realized losses recognized in the year ended December 31, 2021, compared to the realized gains recognized in the corresponding period of the prior year are attributable to a stronger Canadian dollar throughout 2021. The Company manages fluctuations in foreign exchange gains and losses by entering into foreign exchange contracts to fix the foreign exchange rate. Refer to "Financial Derivatives Gains (Losses)" for more information.

Remeasurement Loss on Warrant Liability

	Three months ended December 31, 2021	2020	Percent Change	Year ended December 31, 2021	2020	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Remeasurement loss on warrant liability	4,669	4,289	9	32,599	4,289	660
Per boe ($)	4.85	28.33	(83)	12.09	13.29	(9)

The Company's warrant liability is associated with the 15 million Cenovus Warrants issued to Cenovus as partial consideration for the Marten Hills assets acquired in December 2020. The Cenovus Warrants issued were classified as a financial liability as a result of a cashless exercise provision.

Cenovus exercised all of the outstanding Cenovus Warrants on December 23, 2021, following a call notice issued by Headwater. The Cenovus Warrants were fair valued on the exercise date. The total fair value, along with the proceeds received of $30 million, were credited to capital stock.

The Cenovus Warrants were revalued every reporting period and on the exercise date using a Monte Carlo simulation pricing model. During the three and twelve months ended December 31, 2021, the Company recognized a remeasurement loss on the warrant liability of $4.7 million and $32.6 million, respectively, as a result of the increase in the Company's closing share price to $4.86 on December 23, 2021.

Stock-based Compensation

	Three months ended December 31, 2021	2020	Percent Change	Year ended December 31, 2021	2020	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Stock options	1,115	538	107	3,999	1,414	183
Deferred share units	23	37	(38)	105	63	67
Capitalized stock-based compensation	(150)	-	100	(1,378)	-	100
Stock-based compensation expense	988	575	72	2,726	1,477	85
Per boe ($)	1.03	3.80	(73)	1.01	4.58	(78)

During the three and twelve months ended December 31, 2021, stock-based compensation expense with respect to stock options increased to $1.1 million and $4.0 million, respectively, from $0.5 million and $1.4 million in the corresponding periods of 2020. Stock-based compensation expense increased in both the three and twelve months ended December 31, 2021, as the fair value of the new grants is higher than in 2020 due to an increase in the Company's share price. Stock-based compensation is recorded over a three-year vesting period using graded amortization resulting in a higher proportion of expense being recognized earlier in the vesting term. Headwater capitalized $0.2 million and $1.4 million, respectively, of stock-based compensation during the three and twelve months ended December 31, 2021 as a result of the Company's significant capital expenditure program.

Stock-based compensation relating to deferred share units ("DSUs"), which are currently held by one of the Company's non-management directors, is due to the change in fair value of the DSUs over the period resulting from a corresponding change in the Company's share price. The DSU liability as at December 31, 2021 of $0.2 million is based on a fair value of $5.15 per DSU which is the Company's closing share price on December 31, 2021 (December 31, 2020 - $2.39 per DSU).

Stock Option Plans

The Company has a stock option plan ("Old Option Plan") under which options to purchase common shares of the Company may be granted to directors, officers, employees and consultants of the Company. The exercise price of each option granted under the Old Option Plan is based on the closing price of the common shares on the Toronto Stock Exchange ("TSX") on the trading day prior to the date the option was granted. Options granted under the Old Option Plan generally vest equally over a three-year period and expire four to five years after the grant date. The Company does not intend to grant any additional options under the Old Option Plan.

On March 25, 2020, the Company's Board of Directors (the "Board") approved a new share option plan ("New Option Plan") under which options to purchase common shares of the Company may be granted to directors, officers, employees and consultants of the Company. Under the terms of the New Option Plan, an aggregate number of options equal to 8.0% of the aggregate number of issued and outstanding common shares less the aggregate number of common shares issuable pursuant to outstanding options under the Old Option Plan may be granted. The exercise price of each option granted under the New Option Plan is based on the closing price of the common shares on the TSX on the trading day prior to the date the option was granted and generally options vest equally over a three-year period and expire four years from the date of grant.

The New Option Plan was approved by the Company's shareholders at the Company's annual and special meeting of shareholders held on June 15, 2020.

As at December 31, 2021, there were 1,046,668 stock options outstanding under the Old Option Plan and 8,458,001 stock options outstanding under the New Option Plan.

Subsequent to December 31, 2021, the Board approved an incentive awards plan (the "Awards Plan") providing for the grant of restricted share units ("RSUs") and performance share units ("PSUs") to officers, employees and consultants of the Company and approved the adoption of a new plan (the "DSU Plan") providing for the grant of DSUs to non-management directors of the Company. Refer to the heading "Subsequent Events".

Depletion & Depreciation

	Three months ended December 31, 2021	Three months ended December 31, 2020	Percent Change	Year ended December 31, 2021	Year ended December 31, 2020	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Depletion	15,560	2,540	513	43,882	5,637	678
Depreciation	230	46	400	506	258	96
Depletion & depreciation	15,790	2,586	511	44,388	5,895	653
Depletion per boe ($)	16.17	16.78	(4)	16.27	17.46	(7)
Depreciation per boe ($)	0.24	0.30	(20)	0.19	0.80	(76)
Depletion & depreciation per boe ($)	16.41	17.08	(4)	16.46	18.26	(10)

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.

Depletion and depreciation expense for the three and twelve months ended December 31, 2021, was $15.8 million and $44.4 million, respectively, compared to $2.6 million and $5.9 million recorded in the corresponding periods of 2020. The increase in the absolute level of depletion expense for the three and twelve months ended December 31, 2021 is due to both an increase in production volumes and the carrying value of assets subject to depletion, resulting from the acquisition of Marten Hills assets in December 2020.

Depletion and depreciation per boe decreased during the three and twelve months ended December 31, 2021, when compared to the corresponding period of 2020, primarily due to the Marten Hills assets acquired at a lower cost per boe.

Impairment Reversal

	Three months ended December 31, 2021	Three months ended December 31, 2020	Percent Change	Year ended December 31, 2021	Year ended December 31, 2020	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Impairment reversal	-	(15,054)	(100)	(16,293)	(15,054)	8
Per boe ($)	-	(99.43)	(100)	(6.04)	(46.64)	(87)

The Company concluded there are no indicators of impairment for its Alberta or New Brunswick CGUs as at December 31, 2021.

Impairment Reversal – New Brunswick Cash Generating Unit ("CGU") – Q3 2021

In the third quarter of 2021, due to a significant increase in forecast natural gas pricing, the Company determined an indicator of impairment reversal was present for its New Brunswick CGU. As a result, the Company completed an impairment reversal test and recognized a reversal of previous impairment losses of $16.3 million; this amount represents the full amount available to be reversed.

The recoverable amount was estimated based on the fair value less costs of disposal ("FVLCD") methodology which is calculated using the present value of the CGU's estimated cash flows associated with proved and probable natural gas reserves. The cash flow information was derived from an internal reserve report on the Company's McCully assets which was prepared by management as of September 30, 2021. The projected cash flows used in the FVLCD calculation reflect market assessments of key assumptions as at September 30, 2021, including long-term forecasts for natural gas commodity prices, inflation rates and foreign exchange rates (Level 3 fair value inputs). Cash flow forecasts are also based on the Company's reserves and individual well production profiles, operating and royalty costs and future development costs. Royalty rates used in the FVLCD calculation are consistent with the New Brunswick government's royalty regime in effect as of September 30, 2021.

The discount rate used in the impairment reversal calculation was 12% and was determined based on a peer group weighed average cost of capital factoring in risks specific to the types of reserves. The carrying value of the New Brunswick CGU at September 30, 2021 was $48.9 million prior to any impairment reversal.

Forecast natural gas commodity pricing used in the FVLCD calculation as at September 30, 2021 reflects the benchmark prices set forth in the table below. McCully natural gas prices were calculated by adjusting the Algonquin city-gates natural gas prices to reflect the expected premiums received at Headwater's delivery point, net of transportation costs, if applicable, and heat content.

	2021	2022	2023	2024	2025	2026 – 2030	Thereafter
Algonquin city-gates ($US/mmbtu)	10.50	7.25	5.44	4.37	4.46	4.55 – 4.92	+2%/year
McCully ($CDN/mcf) (1)	17.56	12.43	8.93	6.25	6.86	7.00 – 7.57	+2%/year
Exchange rate ($US/$CDN)	0.80	0.80	0.80	0.80	0.80	0.80	0.80

(1) Realized pricing reflects natural gas production through the winter producing months (January to April and November to December of the applicable year) in 2021 to 2023.

Changes in key assumptions, such as a downward revision in natural gas reserves, a decrease in forecast natural gas commodity prices, changes in foreign exchange rates, an increase in royalties, operating costs or future development costs would decrease the recoverable amount of the CGU and the amount of the impairment reversal with a corresponding decrease to the Company's net income for the period.

As at September 30, 2021, a 1% increase in the discount rate and/or a 5% decrease in forecast operating cash flows would result in the following reduction to the Company's impairment reversal for the period:

	Decrease to impairment reversal
	$
1% increase in discount rate	-
5% decrease in cash flows	(268)
1% increase in discount rate and 5% decrease in cash flows	(2,210)

Impairment Reversal – New Brunswick CGU – Q4 2020

In the fourth quarter of 2020, due to an increase in proved plus probable natural gas reserves as a result of improved recovery and technical revisions, the Company determined an indicator of impairment reversal was present for its New Brunswick CGU. As a result, the Company completed an impairment reversal test and recognized a reversal of previous impairment losses of $15.1 million.

The recoverable amount was estimated based on the FVLCD methodology which is calculated using the present value of the CGU's estimated cash flows associated with proved and probable nature gas reserves. The cash flow information was derived from a reserves report on the Company's McCully assets which was prepared by a third party reserves evaluator as of December 31, 2020. The projected cash flows used in the FVLCD calculation reflect market assessments of key assumptions as at December 31, 2020, including long-term forecasts for natural gas commodity prices, inflation rates and foreign exchange rates (Level 3 fair value inputs). Cash flow forecasts are also based on the Company's reserves and individual well production profiles, operating and royalty costs and future development costs. Royalty rates used in the FVLCD calculation are consistent with the New Brunswick government's royalty regime in effect as of December 31, 2020.

The discount rate used in the impairment reversal calculation was 13% and was determined based on a peer group weighted average cost of capital factoring in risks specific to the types of reserves. The carrying value of the New Brunswick CGU at December 31, 2020 was $37.4 million prior to any impairment reversal.

Forecast natural gas commodity pricing used in the FVLCD calculation as at December 31, 2020 reflects the benchmark prices set forth in the table below. McCully natural gas prices were calculated by adjusting the Algonquin city-gates natural gas prices to reflect the expected premiums received at Headwater's delivery point, transportation costs, if applicable, and heat content.

	2021	2022	2023	2024	2025	2026-2030	Thereafter
Algonquin city-gates ($US/mmbtu)	3.58	3.87	3.85	3.86	3.97	4.05 - 4.33	+2%/year
McCully ($CDN/mcf) (1)	6.47	6.47	6.51	5.74	6.37	6.50 – 7.12	+2%/year
Exchange rate ($US/$CDN)	0.77	0.77	0.76	0.76	0.76	0.76	0.76

(1) Realized pricing reflects natural gas production through the winter producing months (January to April, November, December of the applicable year) in 2021 to 2023.

Changes in any key assumptions, such as a downward revision in natural gas reserves, a decrease in forecast natural gas commodity prices, changes in foreign exchange rates, an increase in royalties, operating costs or future development costs would decrease the recoverable amount of the CGU and the amount of the impairment reversal with a corresponding decrease to the Company's net income for the period.

As at December 31, 2020, a 1% increase in the discount rate and/or a five percent decrease in forecast operating cash flows would result in the following reduction to the Company's impairment reversal for the period:

	Decrease to impairment reversal
	$
1% increase in discount rate	(2,057)
5% decrease in cash flows	(2,576)
1% increase in discount rate and 5% decrease in cash flows	(4,535)

Deferred Income Taxes

	Three months ended December 31, 2021	Three months ended December 31, 2020	Percent Change	Year ended December 31, 2021	Year ended December 31, 2020	Percent Change
	(thousands of dollars)			*thousands of dollars*		
Deferred income tax expense (recovery)	5,064	(7,277)	(170)	5,064	(7,277)	(170)
Canadian statutory income tax rate	23.6%	26.3%	(10)	23.6%	26.3%	(10)

For the three and twelve months ended December 31, 2021, the Company recorded a deferred income tax expense of $5.1 million compared to a deferred income tax recovery of $7.3 million for the three and twelve months ended December 31, 2020. The Company's effective tax provision rate in 2021 is 23.6%.

At December 31, 2021, the Company had approximately $282.8 million of tax pools available to be applied against future taxable income. Headwater was not required to pay income taxes in the current or prior year as the Company had sufficient tax deductions available to shelter taxable income. At current commodity pricing, Headwater expects to be taxable in 2022.

The federal tax pools are estimated as follows:

($ thousands)	Estimated balance at December 31, 2021
Canadian oil and gas property expense	65,931
Canadian development expense	57,677
Canadian exploration expense	63,547
Undepreciated capital cost	65,341
Non-capital losses (1)	25,320
Other	4,934
Total	282,750

(1) The Company's non-capital losses expire in years 2039 and 2040.

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

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

	Three months ended December 31,		Year ended, December 31,	
	2021	2020	2021	2020
	(thousands of dollars)		*(thousands of dollars)*	
Cash flows provided by (used in) operating activities	47,753	(1,451)	111,656	230
Changes in non–cash working capital	978	3,319	6,260	1,222
Transaction costs	-	2,948	-	7,330
Adjusted funds flow from operations (1)	48,731	4,816	117,916	8,782

	Three months ended December 31,		Year ended, December 31,	
	2021	2020	2021	2020
	($/boe)		*($/boe)*	
Cash flows provided by (used in) operating activities	49.62	(9.58)	41.40	0.71
Changes in non–cash working capital	1.02	21.90	2.32	3.79
Transaction costs	-	19.47	-	22.71
Adjusted funds flow netback (2)	50.64	31.79	43.72	27.21

Cash flows provided by operating activities and adjusted funds flow from operations increased significantly to $111.7 million and $117.9 million, respectively, for the year ended December 31, 2021, primarily due to both an increase in realized commodity pricing and sales volumes from the Company’s Marten Hills assets. Headwater drilled 51 (51.0 net) crude oil wells in 2021 and grew heavy oil sales volumes from 246 bbls/d in the year ended December 31, 2020, to 6,661 bbls/d in the year ended December 31, 2021.

	Three months ended December 31,		Year ended December 31,	
	2021	2020	2021	2020
	(thousands of dollars)		*(thousands of dollars)*	
Net income	27,927	16,919	45,828	6,707
Remeasurement loss on warrant liability	4,669	4,289	32,599	4,289
Adjusted net income (3)	32,596	21,208	78,427	10,996

(1) Refer to “Management of capital” in note 18 of the audited annual financial statements and to “Non-GAAP and Other Financial Measures” within this MD&A.
(2) Non-GAAP ratio. Refer to the advisory “Non-GAAP and Other Financial Measures”.
(3) Non-GAAP measure. Refer to “Non-GAAP and Other Financial Measures” within this MD&A.

Net income and adjusted net income increased significantly to $45.8 million and $78.4 million, respectively, for the year ended December 31, 2021, due to higher cash flows provided by operating activities (discussed above) partially offset by non-cash items including higher depletion and depreciation of $44.4 million, deferred income tax expense of $5.1 million and stock-based compensation of $2.7 million.

Capital Expenditures

	Three months ended December 31, 2021	2020	Percent Change	Year ended December 31, 2021	2020	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Lease acquisition and retention	283	-	100	1,721	293	487
Geological and geophysical	115	82	40	563	175	222
Site preparation	6,077	1,646	269	11,020	1,646	570
Drilling and completions	16,024	-	100	64,844	-	100
Equipping and facilities	26,542	(3)	n/a	62,228	108	n/a
Corporate	2	23	(91)	13	55	(76)
Capital expenditures (1)	49,043	1,748	2706	140,389	2,277	6066
Property acquisition	-	135,297	(100)	-	135,297	(100)
Capital expenditures including acquisition (1)	49,043	137,045	(64)	140,389	137,574	2

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

During the year ended December 31, 2021, Headwater drilled a total of 51 (51.0 net) crude oil wells (6-leg and 8-leg multi-laterals), 4 (4.0 net) source wells and 3 (3.0 net) stratigraphic test wells with a 100% success rate.

During the three months ended December 31, 2021, the Company invested a total of $49.0 million on capital expenditures including $16.0 million on drilling and completions, $26.5 million on equipping and facilities, $6.1 million on site preparation, including road construction, and $0.4 million on lease acquisition and geological and geophysical costs.

During the year ended December 31, 2021, the Company invested a total of $140.4 million on capital expenditures including $64.8 million on drilling and completions, $62.2 million on equipping and facilities, $11.0 million on site preparation, including road construction, and $2.3 million on lease acquisition and geological and geophysical costs. Headwater constructed a joint gas processing facility during the year with first sales gas realized in September 2021. During the year ended December 31, 2021, Headwater also commenced construction of its 15,000 bbls/d oil processing facility which was commissioned in March 2022.

Drilling Activity

The following table summarizes the Company's drilling results:

	Three months ended December 31, 2021 Gross	2021 Net	2020 Gross	2020 Net	Year ended December 31, 2021 Gross	2021 Net	2020 Gross	2020 Net
Crude oil (1)	11	11.0	-	-	51	51.0	-	-
Natural gas	-	-	-	-	-	-	-	-
Injection	-	-	-	-	-	-	-	-
Source/stratigraphic test	3	3.0	-	-	7	7.0	-	-
Dry and abandoned	-	-	-	-	-	-	-	-
Total	14	14.0	-	-	58	58.0	-	-
Success	100%	100%	N/A	N/A	100%	100%	N/A	N/A

(1) Of the 51 (51.0 net) crude oil wells drilled during the year ended December 31, 2021, 3 (3.0 net) were converted to water injection wells (1 in April 2021 and 2 in October 2021) and 4 (4.0 net) will be converted to water injection wells in 2022.

Marten Hills Property Acquisition

On November 8, 2020, the Company entered into a purchase and sale agreement with Cenovus to acquire the entirety of Cenovus' assets in the Marten Hills area of Alberta. The acquisition was completed on December 2, 2020 (the "Acquisition"), for total consideration of $135.3 million, comprised of $32.8 million of cash, 50 million common shares of the Company valued at $96.5 million using Headwater's closing share price on the closing date of the Acquisition, and 15 million Cenovus Warrants valued at $6.0 million. The effective date of the acquisition was October 1, 2020.

The acquired assets included 100% working interest in Marten Hills heavy oil properties and undeveloped land. The Company assumed certain transportation commitments from Cenovus and was required to spend $100 million in capital expenditures on the acquired assets by December 31, 2022. As at December 31, 2021, Headwater had satisfied this capital commitment.

Decommissioning Liabilities

As at December 31, 2021, the decommissioning liabilities of the Company were $27.6 million. The Company recorded an increase of $10.9 million in the obligation from the decommissioning liability of $16.7 million as at December 31, 2020. This increase of $10.9 million is due to additions of $10.8 million as a result of the Company's capital expenditure program and accretion expense of $0.3 million partially offset by a downward change in estimate of $0.2 million. The change in estimate is a result of an increase to the risk-free rate to 1.7% at December 31, 2021 from 1.2% at December 31, 2020, partially offset by an increase to the inflation rate to 1.8% at December 31, 2021 from 1.5% at December 31, 2020. The total undiscounted uninflated amount of estimated cash flows required to settle these obligations is $26.4 million (December 31, 2020 - $15.5 million).

2021 Guidance

A summary of the guidance that was provided by the Company in November 2021 compared to the actual results from 2021, are as follows:

	2021 Guidance	2021 Actuals
2021 annual average production (boe/d)	7,400	7,393
Q4 2021 average production (boe/d)	10,400	10,449
Exit adjusted working capital (1)	$66 million	$93 million
Capital expenditures (2)	$140 million	$140 million

(1) Refer to "Management of capital" in note 18 of the audited annual financial statements and to "Non-GAAP and Other Financial Measures" within this MD&A.
(2) Non-GAAP measure. Refer to "Non-GAAP and Other Financial Measures" within this MD&A

Exit adjusted working capital is $27 million higher than 2021 guidance due to the exercise by Cenovus of the 15 million Cenovus Warrants for cash proceeds of $30 million partially offset by a decrease in cash flows provided by operating activities due to lower realized commodity pricing when compared to forecasted prices in the fourth quarter of 2021.

2022 Guidance

The following table summarizes Headwater's 2022 guidance as released on March 10, 2022, compared to the guidance issued on February 1, 2022. Headwater expects to fund capital expenditures through existing working capital and forecasted cash flows from operating activities.

	2022 Guidance February 1, 2022	2022 Guidance March 10, 2022
Average Daily Production		
Annual (boe/d) (1)	12,500	12,500
Fourth quarter average (boe/d) (2)	15,000	15,000
Pricing		
Crude oil - WTI (US$/bbl)	75.00	88.00
Crude oil - WCS (Cdn$/bbl)	78.50	97.00
Exchange rate (US$/Cdn$)	0.79	0.79
Natural gas - AGT (US$/mmbtu) (3)	13.90	14.19
Financial Summary ($millions)		
Capital expenditures (4)	145	145
Cash flows provided by operating activities	212	248
Adjusted funds flow from operations (5)	223	259
Estimated exit working capital	171	207
Estimated exit adjusted working capital (5)	171	207

(1) Comprised of 11,500 bbls/d of heavy oil and 6.2 mmcf/d of natural gas
(2) Comprised of 13,770 bbls/d of heavy oil and 7.4 mmcf/d of natural gas
(3) The AGT price is the average for the winter producing months in the McCully field which include January – April 2022 and November – December 2022.
(4) Non-GAAP measure. Refer to "Non-GAAP and Other Financial Measures" within this MD&A
(5) Refer to "Management of capital" in note 18 of the audited annual financial statements and to "Non-GAAP and Other Financial Measures" within this MD&A.

With the increase in realized commodity pricing in the first quarter of 2022, the Company expects to generate adjusted funds flow from operations of $259 million and exit adjusted working capital of $207 million.

Liquidity and Capital Resources

Headwater's liquidity depends on the Company's cash flows provided by operating activities, supplemented as necessary by equity and debt financings.

As at December 31, 2021, the Company had cash of $114.7 million, working capital of $89.8 million and no outstanding debt. The Company expects to have adequate liquidity to fund its 2022 capital expenditure budget of $145 million and contractual obligations in the near term through existing working capital and forecasted cash flows from operations. Headwater anticipates that it will make use of debt or equity financing for any substantial expansion of its capital program or to finance any significant acquisitions.

Contractual Obligations and Commitments

The following table details the contractual maturities of the Company's financial liabilities as at December 31, 2021:

	Within 1 year	1 to 5 years
	$	$
Accounts payable and accrued liabilities	52,970	-
Financial derivative liability	3,924	-
DSU liability	196	-
Lease liability	855	695
Total	57,945	695

As at December 31, 2021, the Company is committed to future payments under the following agreements:

	Total	2022	2023	2024	2025	2026	Thereafter
	$	$	$	$	$	$	$
Transportation (1) (2)	104,528	9,315	10,828	11,043	12,121	13,222	47,999

(1) Headwater has the following transportation commitments:
   a. 9- year take-or-pay transportation agreement with a minimum volume commitment of 10,000 boe/d.
   b. 9- year financial commitment at $1,890 thousand per year adjusted for inflation.
   c. 9-year take-or-pay transportation agreement with a current minimum volume commitment of 1,250 boe/d increasing to 6,250 boe/d in year 3 and to 9,000 boe/d in year 6.

(2) Excludes leases accounted for under IFRS 16.

In connection with the Acquisition, Headwater was required to spend $100 million in capital expenditures on the acquired assets by December 31, 2022. As at December 31, 2021, Headwater had satisfied this capital commitment.

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

Common Share Information

Share Capital

(thousands)	Three months ended December 31,		Year ended December 31,	
	2021	2020	2021	2020
Weighted average outstanding common shares (1)				
-Basic	204,005	161,365	199,802	139,379
-Diluted	220,958	168,600	215,861	145,377
Outstanding securities at December 31, 2021				
-Common shares				217,681
-Stock options – weighted average strike price of $2.36				9,505
-Warrants – strike price of $0.92 (2)				15,387

(1) The Company uses the treasury stock method to determine the dilutive effect of stock options, Warrants (as defined below) and the Cenovus Warrants. 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.

(2) Issued on the Recapitalization Transaction (as defined below) as part of the non-brokered private placement. As at December 31, 2021, these Warrants are fully exercisable with a strike price of $0.92.

Recapitalization Transaction

On March 4, 2020, the Company completed a recapitalization transaction (the "Recapitalization Transaction"). The Recapitalization Transaction involved the following:

- A non-brokered private placement of 21,739,130 units of the Company at a price of $0.92 per unit for aggregate gross proceeds of $20.0 million. Each unit was comprised of one common share and one common share purchase warrant ("Warrant") of the Company. Each Warrant entitles the holder to purchase one common share at a price of $0.92 per common share for a period of 4 years from the issuance date. The Warrants vested and became exercisable as to one-third upon the 20-day volume weighted average price of the common shares equaling or exceeding $1.30, $1.60 and $1.90, respectively. Pursuant to the rules of the TSX, the non-brokered private placement was approved by shareholders of the Company at a special meeting held on March 4, 2020.

- Concurrently with the closing of the non-brokered private placement, the appointment of a new management team and reconstitution of the Board was completed.

- A brokered private placement of 32,608,696 subscription receipts ("Subscription Receipts") of the Company, which were issued at a price of $0.92 per Subscription Receipt through a syndicate of dealers for aggregate gross proceeds of $30.0 million, was completed on February 11, 2020. Pursuant to the terms of the Subscription Receipts, upon completion of the non-brokered private placement, reconstitution of the Board and appointment of the new management team on March 4, 2020, the net proceeds of the brokered private placement were released to the Company and each holder of Subscription Receipts received one common share for each Subscription Receipt held.

- Pursuant to the Recapitalization Transaction, the Company incurred $4,382 thousand of transaction costs and $1,905 thousand of share issue costs.

Cenovus Warrants

On December 23, 2021, Cenovus exercised 15 million Cenovus Warrants for 15 million common shares for total proceeds of $30 million. The total fair value of $42.9 million, along with the proceeds received, were credited to capital stock.

Stock Options

During the year ended December 31, 2021, 1,726 thousand stock options were exercised for 1,282 thousand common shares on a cashless basis. 17,000 stock options were exercised for 17,000 common shares for total proceeds of $18 thousand. Contributed surplus related to the options exercised of $972 thousand was transferred to capital stock.

During the year ended December 31, 2020, 2,550 thousand stock options were exercised for 2,550 common shares for cash proceeds of $2,077 thousand. Contributed surplus related to the options exercised of $1,121 thousand was transferred to capital stock.

Warrants

During the year ended December 31, 2021, 6,290 thousand Warrants were exercised for 6,276 thousand common shares for total proceeds of $5.7 million. The associated fair value of the Warrants of $2,222 thousand, along with the proceeds received, were transferred to capital stock.

Cenovus Secondary Offering

In December 2020, Headwater issued 50 million common shares of the Company to Cenovus as part of the consideration for the acquired assets valued at a closing price of $1.93 per common share. On October 14, 2021, Cenovus closed a $227.5 million bought deal secondary offering of 50 million common shares of the Company. Post-closing of the offering, the investor agreement (the "Investor Agreement") between Cenovus and Headwater was terminated. In connection with the termination of the Investor

Agreement, one of Cenovus' nominees on the Board resigned. The other nominee of Cenovus on the Board will continue to serve as a director of the Company notwithstanding the termination of the Investor Agreement. Headwater did not receive any proceeds of the secondary offering. Cenovus reimbursed the Company for all of its expenses incurred in connection with the secondary offering.

Total Market Capitalization

The Company's market capitalization at December 31, 2021 was approximately $1.1 billion.

(thousands)	December 31, 2021
Common shares outstanding	217,681
Share price (1)	$5.15
Total market capitalization	$1,121,057

(1) Represents the last price traded on the TSX on December 31, 2021.

As at March 10, 2022 the Company had 223,727,180 common shares outstanding.

(thousands)	March 10, 2022
Outstanding securities at March 10, 2022	
-Common shares	223,727
-Stock options – weighted average strike price of $2.38	9,367
-Warrants – strike price of $0.92	8,594

Environmental, Social and Governance ("ESG") Update

Headwater remains committed to strong ESG performance. Recent achievements related to the Company's ESG strategy include:

- The Company's joint gas processing facility, commissioned in the third quarter of 2021, in combination with pipeline infrastructure installed in the first quarter of 2021, has resulted in an approximate 50% reduction in Headwater's CO_2e emissions intensity per barrel of oil equivalent over the 2021 calendar year.

- Headwater's freshwater usage intensity has decreased by greater than 80% from the first quarter of 2021 which places the Company in the top decile of its peer group, due to changes in drilling strategy using primarily oil-based mud systems.

The Board continually focuses on ensuring that its governance structure is appropriate and following best practices given Headwater's size and stage of development. The primary responsibility of Headwater's Corporate Governance and Sustainability Committee, which is comprised of independent members of the Board, is to develop the Company's approach to matters concerning corporate governance, sustainability, human resources and compensation. In addition, the Board has also established the Audit Committee and Reserves Committee, which are both comprised of independent members of the Board, to ensure the integrity of the financial and reserves reporting of the Company. For additional information relating to the governance policies and structure of the Company see the Company's management information circular dated March 29, 2021 for the annual and special meeting of the shareholders held on May 13, 2021, which is available on SEDAR at www.sedar.com and the information under the heading Corporate Responsibility on the Company's website at at www.headwaterexp.com.

Related Party Transactions

Key management personnel of the Company include its directors and senior management. In 2021, the Company recorded $2.8 million (2020 – $2.9 million) relating to compensation of key management personnel. In 2021, stock-based compensation expense relating to compensation of key management personnel was $2.7 million (2020 – $1.3 million).

Selected Annual Financial Information

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

	2021	2020	2019
(thousands of dollars except share data and production volumes)			
Average production volumes (boe/d)	7,393	882	620
Average sales volumes (boe/d)	7,390	882	620
Total sales, net of blending [(1)]	179,517	9,156	9,333
Net income	45,828	6,707	2,815
Net income per share			
-basic	0.23	0.05	0.03
-diluted	0.21	0.05	0.03
Adjusted net income [(1)]	78,427	10,996	2,815
Cash flows provided by operating activities	111,656	230	8,861
Adjusted funds flow from operations [(2)]	117,916	8,782	8,206
Working capital	89,775	70,528	64,622
Adjusted working capital [(2)]	92,929	80,759	63,141
Capital expenditures [(1)]	140,389	2,277	685
Property acquisition	-	135,297	-
Total assets	488,807	300,685	128,271

(1) Non-GAAP measure. Refer to "Non-GAAP and Other Financial Measures" within this MD&A.
(2) Refer to "Management of capital" in note 18 of the audited annual financial statements and to "Non-GAAP and Other Financial Measures" within this MD&A.

Following the Acquisition in December 2020, Headwater has grown annual average production volumes significantly from 620 boe/d in 2019 to 7,393 boe/d in 2021. This production growth, in combination with higher commodity prices as a result of the increased demand for crude oil following the global recovery from the COVID-19 pandemic, resulted in a significant increase in cash flows provided by operating activities of $111.7 million and adjusted funds flow from operations of $117.9 million in 2021.

Summary of Quarterly Information

	Q4/21	Q3/21	Q2/21	Q1/21	Q4/20	Q3/20	Q2/20	Q1/20
Financial *(thousands of dollars except share data)*								
Total sales, net of blending [(1)] [(2)]	70,125	48,841	37,429	23,122	6,283	-	565	2,308
Cash flows provided by (used in) operating activities	47,753	27,888	23,232	12,783	(1,451)	(364)	863	1,182
Adjusted funds flow from (used in) operations [(3)]	48,731	31,524	23,182	14,479	4,816	(837)	(610)	5,413
Per share - basic [(4)]	0.24	0.16	0.12	0.07	0.03	(0.01)	-	0.05
- diluted [(4)]	0.22	0.14	0.10	0.07	0.03	(0.01)	-	0.05
Net income (loss)	27,927	26,106	4,588	(12,793)	16,919	(1,723)	(1,679)	(6,810)
Per share - basic	0.14	0.13	0.02	(0.07)	0.10	(0.01)	(0.01)	(0.06)
- diluted	0.13	0.12	0.02	(0.07)	0.10	(0.01)	(0.01)	(0.06)

Adjusted net income (loss) [2]	32,596	28,868	10,561	6,402	21,208	(1,723)	(1,679)	(6,810)
Per share - basic [4]	0.16	0.14	0.05	0.03	0.13	(0.01)	(0.01)	(0.06)
- diluted [4]	0.15	0.13	0.05	0.03	0.13	(0.01)	(0.01)	(0.06)
Capital expenditures [2]	49,043	37,293	16,781	37,272	1,748	61	398	70
Property acquisition	-	-	-	-	135,297	-	-	-
Depletion and depreciation	15,790	10,889	10,459	7,250	2,586	75	754	7,250
Working capital	89,775	16,490	32,586	28,687	70,528	112,536	113,718	114,200
Adjusted working capital [3]	92,929	63,709	69,697	58,367	80,759	112,667	113,569	114,200
Shareholders' equity	397,791	295,528	268,191	257,461	269,030	155,148	156,386	157,235
Weighted average shares *thousands)*								
Basic	204,005	202,313	197,445	195,322	161,365	145,044	144,749	105,436
Diluted [5]	220,958	218,190	213,905	195,322	168,600	145,044	144,749	105,436
Shares outstanding, end of period *(thousands)*								
Basic	217,681	202,466	202,286	195,574	195,106	145,044	145,044	144,327
Diluted [6]	242,448	240,447	240,257	240,456	238,121	158,627	151,381	145,552
Operating *(6:1 boe conversion)*								
Average daily production								
Heavy oil (*bbls/d*)	9,377	7,637	6,185	3,385	979	-	-	-
Natural gas *(mmcf/d)*	6.4	0.3	2.3	8.5	4.0	-	2.4	8.9
Natural gas liquids *(bbls/d)*	-	-	5	5	3	-	-	7
Barrels of oil equivalent *(boe/d)* [7]	10,449	7,688	6,565	4,805	1,646	-	396	1,487
Average daily sales volumes *(boe/d)* [7] [8]	10,459	7,613	6,653	4,768	1,646	-	396	1,487
Average selling prices								
Heavy oil (*$/bbl*)	75.12	70.00	64.20	55.72	45.05	-	-	-
Natural gas *($/mcf)*	8.46	4.49	2.76	7.48	5.37	-	2.27	2.49
Natural gas liquids *($/bbl)*	-	-	73.99	66.55	56.23	-	-	57.90
Barrels of oil equivalent *($/boe)*	72.62	69.71	61.52	52.51	39.90	-	13.63	15.12
Netbacks ($/boe) [4] [9]								
Operating								
Sales, net of blending	72.88	69.73	61.83	53.89	41.50	-	15.67	17.06
Realized gain on financial derivatives	1.41	-	0.24	(1.28)	10.42	-	-	29.09
Royalties	(11.34)	(10.46)	(8.84)	(5.49)	(3.86)	-	(0.39)	(0.42)
Transportation	(6.98)	(8.68)	(8.21)	(6.04)	(5.10)	-	-	-
Production expense	(4.20)	(4.42)	(4.89)	(5.62)	(7.92)	-	(14.79)	(4.78)
Operating netback, including financial derivatives *($/boe)*	51.77	46.17	40.13	35.46	35.04	-	0.49	40.95
General and administrative	(1.23)	(1.40)	(1.60)	(1.97)	(4.64)	-	(23.33)	(5.05)
Interest income and other expense [10]	0.10	0.24	(0.23)	0.26	1.39	-	6.00	4.10
Adjusted funds flow netback *($/boe)*	50.64	45.01	38.30	33.75	31.79	-	(16.84)	40.00

(1) Heavy oil sales are netted with blending expense to compare the realized price to benchmark. In the audited annual financial statements, blending is recorded in blending and transportation expense.
(2) Non-GAAP measure. Refer to "Non-GAAP and Other Financial Measures" within this MD&A.
(3) Refer to "Management of capital" in note 18 of the audited annual financial statements and to "Non-GAAP and Other Financial Measures" within this MD&A.
(4) Non-GAAP ratio. Refer to the advisory "Non-GAAP and Other Financial Measures".
(5) Diluted weighted average shares outstanding includes the impact of any stock options, Warrants and Cenovus Warrants that would be outstanding as dilutive instruments using the treasury stock method.
(6) Includes in-the-money dilutive instruments as at December 31, 2021 which include 9.4 million stock options with a weighted average exercise price of $2.33 and 15.4 million Warrants with an exercise price of $0.92.
(7) See barrels of oil equivalent under "Oil and Gas Measures".
(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 accretion on decommissioning liabilities and interest on the lease liability.

2021 was a transformational year for Headwater following the Recapitalization Transaction and Acquisition in 2020. The Company spent $140.4 million on its capital program in 2021 growing production from 1,646 boe/d in the fourth quarter of 2020 to 10,449 boe/d in the fourth quarter of 2021. The recovery of crude oil prices and the increase in the Company's average production has resulted in a significant increase in sales, cash flows provided by operating activities and net income.

Prior to the Acquisition in December 2020, Headwater solely produced natural gas and liquids out of its McCully assets in New Brunswick. Headwater's east coast natural gas sales are priced at AGT. The AGT market has been characterized by excess demand during the winter season resulting in significant premiums in the sales price for natural gas during the winter season as compared to prices during other periods of the year. In response to this trend in natural gas prices, since 2015, the Company has shut-in most of its producing natural gas wells in the McCully field in New Brunswick for a portion of the summer and fall period to time the start-up of production, and the associated recovery of flush volumes, with peak winter pricing to maximize adjusted funds flow from operations and to retain Headwater's reserves for production in future years.

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) Awards Plan and DSU Plan

At the meeting of the Board held on March 10, 2022, the directors approved a new Awards Plan providing for the grant of RSUs and PSUs to officers, employees and consultants of the Company. The maximum number of common shares issuable under the Awards Plan shall not at any time exceed 6.0% of the total common shares outstanding less the aggregate number of common shares reserved for issuance pursuant to the New Option Plan and the Old Option Plan of the Company. 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. The common shares underlying PSUs are adjusted based on a payout multiplier ranging from 0 to 2 times, which is determined based on certain corporate performance measures, as determined by the Board.

Until the Company receives approval of the Awards Plan from the shareholders of the Company in accordance with the rules of the TSX, the Company will not be able to issue common shares on settlement of RSUs and PSUs and will instead be required to make a cash payment equal to the value of the common shares underlying the applicable RSUs or PSUs.

At the meeting of the Board held on March 10, 2022, the Board approved the adoption of the new DSU Plan. The DSU Plan 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 TSX. The directors may also elect to receive all of their annual cash compensation in the form of DSUs provided that such election must be made on December 1st of the preceding calendar year (or within a certain prescribed time frame if an individual becomes a director after the commencement of a calendar year or after the initial adoption of the DSU Plan) and after such date the election will be irrevocable for such year. DSUs are measured at fair value using the 5-day volume weighted average price on the date of grant.

b) Financial derivative commodity contracts and foreign exchange contracts

Subsequent to December 31, 2021, Headwater entered into the following financial derivative contracts:

Commodity	Index	Type	Term	Daily Volume	Contract Price
Natural Gas	AGT	Fixed	Feb 2022	5,000 mmbtu/d	Cdn$20.17/mmbtu
Natural Gas	AGT	Fixed	March 2022	2,500 mmbtu/d	Cdn$11.73/mmbtu
Natural Gas	AGT	Fixed	April 2022	5,000 mmbtu/d	Cdn$6.48//mmbtu
Natural Gas	AGT	Fixed	Dec 2022- Mar 2023	2,500 mmbtu/d	Cdn$17.91/mmbtu

Subsequent to December 31, 2021, Headwater entered into the following foreign exchange contracts:

Type	Buy Currency	Sell Currency	Rate	Notional Amount	Settlement Date
Forward contract	CAD	USD	WMR noon rate, January 2022 average	US$30,100,000	February 25, 2022
Forward contract	CAD	USD	WMR noon rate, February 2022 average	US$29,600,000	March 25, 2022
Forward contract	CAD	USD	WMR noon rate, March 2022 average	US$40,300,000	April 25, 2022

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

Adjusted Net Income

Adjusted net income is a non-GAAP financial measure which management utilizes to present a measure of financial performance that is more comparable over periods. It is calculated by adding the remeasurement loss on warrant liability associated with the Cenovus Warrants to net income.

	Three months ended December 31,		Year ended December 31,	
	2021	2020	2021	2020
	(thousands of dollars)		*(thousands of dollars)*	
Net income	27,927	16,919	45,828	6,707
Remeasurement loss on warrant liability	4,669	4,289	32,599	4,289
Adjusted net income	32,596	21,208	78,427	10,996

Heavy oil sales, net of blending

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

	Three months ended December 31, 2021	2020	Year ended December 31, 2021	2020
	(thousands of dollars)		*(thousands of dollars)*	
Heavy oil sales	70,038	4,400	178,434	4,400
Blending expense	(5,162)	(343)	(11,423)	(343)
Heavy oil sales, net of blending expense	64,876	4,057	167,011	4,057

Total sales, net of blending

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

	Three months ended December 31, 2021	2020	Year ended December 31, 2021	2020
	(thousands of dollars)		*(thousands of dollars)*	
Total sales	75,287	6,626	190,940	9,499
Blending expense	(5,162)	(343)	(11,423)	(343)
Total sales, net of blending expense	70,125	6,283	179,517	9,156

Capital expenditures and capital expenditures including acquisition

Management utilizes capital expenditures and capital expenditures including acquisition to measure total cash capital expenditures incurred in the period. Capital expenditures represents capital expenditures – exploration and evaluation and capital expenditures – property, plant and equipment in the statement of cash flows in the Company's audited annual financial statements.

	Three months ended December 31, 2021	2020	Year ended December 31, 2021	2020
	(thousands of dollars)		*(thousands of dollars)*	
Cash flows used in investing activities	47,047	34,374	109,127	34,404
Property acquisition	-	(32,781)	-	(32,781)
Restricted cash	1,248	(1,477)	1,477	(797)
Change in non-cash working capital	748	1,632	29,785	1,451
Capital expenditures	49,043	1,748	140,389	2,277
Property acquisition	-	135,297	-	135,297
Capital expenditures including acquisition	49,043	137,045	140,389	137,574

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. In addition to being a capital management measure, adjusted funds flow from operations is used by management to assess the performance of the Company's oil and gas properties. Adjusted funds flow from operations is an indicator of operating performance as it varies in response to production levels and management of production and transportation costs. Management believes that by eliminating changes in non-cash working capital and transaction costs, adjusted funds flow from operations is a useful measure of operating performance. Management removes transaction costs as these costs relate to acquisitions/dispositions and not the operations of the underlying properties.

	Three months ended December 31,		Year ended, December 31,	
	2021	2020	2021	2020
	(thousands of dollars)		*(thousands of dollars)*	
Cash flows provided by operating activities	47,753	(1,451)	111,656	230
Changes in non–cash working capital	978	3,319	6,260	1,222
Transaction costs	-	2,948	-	7,330
Adjusted funds flow from operations	48,731	4,816	117,916	8,782

Adjusted Working Capital

Adjusted working capital is a capital management measure which management uses to assess the Company's liquidity.

	Year ended December 31,	
	2021	2020
	(thousands of dollars)	
Working capital	89,775	70,528
Financial derivative receivable	(770)	(74)
Financial derivative liability	3,924	-
Warrant liability	-	10,305
Adjusted working capital	92,929	80,759

Non-GAAP Ratios

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

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

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

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

Adjusted funds flow per share and adjusted net income per share

Adjusted funds flow per share and adjusted net income per share 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 per share and adjusted net income per share are calculated as adjusted funds flow from operations or adjusted net income divided by weighted average shares outstanding on a basic or diluted basis.

Royalty rate

Corporate royalty rate is calculated as total royalties as a percentage of total sales, net of blending expense.

Per boe numbers

This MD&A represents various results on a per boe basis including Headwater average realized sales price, financial derivatives gains (losses) per boe, royalty expense per boe, transportation expense per boe, production expense per boe, general and administrative expenses per boe, interest income and other expense per boe, remeasurement loss on warrant liability per boe, stock-based compensation expense per boe, depletion and depreciation per boe and impairment reversal per boe. These figures are calculated using sales volumes.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

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

The CEO and the CFO have evaluated the effectiveness of Headwater's disclosure controls and procedures as at December 31, 2021 and have concluded that such disclosure controls and procedures were effective as at such date.

The CEO and the CFO of Headwater have designed, or caused to be designed under their supervision, internal controls over financial reporting ("ICFR") as defined in NI 52-109. The control framework Headwater's officers used to design the Company's ICFR is the COSO Framework published by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). The CEO and CFO have concluded that the Company's ICFR were effective as of December 31, 2021. There have been no changes in the ICFR during the period from October 1, 2021 to December 31, 2021 that have materially affected, or are reasonably likely to materially affect the Company's ICFR.

It should be noted that while Headwater's CEO and CFO believe that the Company's internal controls and procedures provide a reasonable level of assurance and that they are effective, they do not expect these controls will prevent all errors or fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Critical Accounting Estimates

Use of estimates and judgments

The preparation of the Company's financial statements in accordance with IFRS requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Such estimates and assumptions are evaluated at each reporting date and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Actual results may differ from the estimated amounts as future confirming events occur and more information is obtained by management. The Company has identified the following areas requiring significant judgments, assumptions or estimates.

Impact of COVID-19

In March 2020, the World Health Organization declared a global pandemic following the emergence and rapid spread of a novel strain of the coronavirus ("COVID-19"). The outbreak and subsequent measures enforced to limit the spread of the pandemic contributed to volatility in financial markets.

The outbreak and current market conditions have increased the complexity of estimates and assumptions used to prepare the audited annual financial statements, particularly related to recoverable amounts. The Company will continue to update its significant judgments, estimates and assumptions for COVID-19 and the emergence of new COVID-19 variants as the impacts, if any, on commodity prices and equity markets unfold.

Climate change

The following provides certain disclosures as to the impact of climate change on the amounts recorded in the financial statements as at and for the year ended December 31, 2021. 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. With respect to climate reporting, the International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators have issued a proposed national instrument 51-107 Disclosure of Climate-Related Matters. The cost to comply with these standards, and others that may be developed or evolve over time, has not yet been quantified.

The Company has considered the impact of the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels in its assessment as a possible indication of impairment of its oil and gas properties. The Company completed the analysis of triggers for impairment as at December 31, 2021 and climate risk/climate change, in of itself, did not result in the Company completing an impairment test. The Company has considered the impact of the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels in its assessment of depletion on its oil and gas properties. Depletion of the Company's oil and gas properties was based on proved and probable reserves, the life of which is generally less than 20 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 2021 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 based on the current rate of $50 per tonne.

The evolving energy transition and general sentiment to the oil and gas industry may result in reduced access to capital markets. Management will continue to adjust the capital structure to the dynamic environment.

The Company's financial results for 2021 were not directly impacted from a climate event. In 2021, the Company did not incur material weather related damages to its property, plant and equipment. During 2021, management is not aware of a material disruption in its supply chain or the marketers of the Company's product related to climate events.

The Company maintains insurance coverage that provides a level of insurance for certain events that may arise due to climate change factors; however, the Company's insurance program is subject to limits and various restrictions. No claims were made under the Company's insurance policies in 2021 with respect to climate related matters.

a) Critical Judgments in Applying Accounting Policies

Business Combinations

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value is estimated based on information available at the date of acquisition and requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of exploration and evaluation assets and property, plant and equipment acquired generally require the most judgment and include estimates of the cash flows associated with proved and probable reserves acquired which is impacted by assumptions related to forecasted production, forecasted operating and royalty costs, future development costs, future crude oil and natural gas commodity prices, foreign exchange rates, and discount rates. Assumptions are also required to determine the fair value of decommissioning liabilities associated with the properties. Changes in any of these assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities (including deferred income tax liabilities) in the acquisition equation. Future net income (loss) will be affected as the fair value on initial recognition impacts future depletion expense, as well as the risk of potential impairment in future periods.

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 impairment testing is required.

The Company's CGUs as at December 31, 2021 include its Alberta CGU comprised of its Marten Hills assets and its New Brunswick CGU consisting of its McCully assets.

Exploration and evaluation ("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.

b) 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 exploration and evaluation 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:

i) 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.

ii) 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.

iii) 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.

iv) 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, property, plant, and equipment acquired in business combinations, deferred income taxes 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 (NI) 51-101, “Standards of Disclosure for Oil and Gas Activities”. 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 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.

Valuation of financial instruments

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

The estimated fair value of the warrant liability, which is considered a financial instrument, uses the Monte Carlo simulation pricing model which is based on assumptions including volatility, risk-free interest rate and the expected term.

Valuation of Warrants and stock options

The estimated fair values of the Warrants issued as part of the non-brokered private placement in connection with the Recapitalization Transaction and stock options issued under the Company’s stock option plans were based on the Black-Scholes pricing model incorporating assumptions on volatility, risk-free interest rate, forfeiture rate and the expected term.

Future accounting pronouncements

On January 23, 2020, the IASB announced an amendment to IAS 1 “Presentation of financial statements” re: classification of liabilities as current or non-current which is effective for annual periods beginning on or after January 1, 2023. The amendment clarifies that the classification of liabilities as current or non-current should be based on rights that are in existence at the end of the reporting period.

On May 7, 2021, the IASB announced an amendment to IAS 12 “Income Taxes” re: deferred tax assets and liabilities arising from a single transaction which is effective for annual periods beginning on or after January 1, 2023. The amendment narrows the scope of the initial recognition exemption so that is does not apply to transactions that give rise to equal and offsetting temporary differences. As a result, companies will need to recognize a deferred tax asset and a deferred tax liability for temporary differences arising on initial recognition of a lease and of a decommissioning provision.

The Company does not plan to early adopt any amendments issued but not yet effective and has not yet assessed their impact.

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:

- The impact of the Russian Ukrainian conflict on commodity prices and the world economy could affect the Company's results, business, financial conditions or liquidity;
- Natural disasters, terrorist acts, civil unrest, war, pandemics and other disruptions and dislocations may affect the Company's results, business, financial conditions or liquidity;
- 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 it properties;
- 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;
- Public health risks including relating to the COVID-19 pandemic 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 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 US dollar denominated benchmarks; and
- The risk of significant interruption or failure of the Company's information technology systems and related data and control systems or a significant breach that could adversely affect the Company's operations.

Additional risks and information on risk factors are included in the Annual Informational Form for the year ended December 31, 2021, dated March 10, 2022, which is available on the Company's website at www.headwaterexp.com and under the Company's profile on SEDAR at www.sedar.com.

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 investment grade; and
- Implementation of cyber security protocols and procedures to reduce to risk of failure of breach of data.

Oil and Gas Metrics

Barrels of Oil Equivalent

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.

Reserves Information

Reserves information as at December 31, 2021 as presented herein is based on a report (the “2021 GLJ Reserves Report”) prepared by GLJ Ltd. (“GLJ”) assessing the Company’s reserves effective December 31, 2021 which were prepared in accordance with standards of the Canadian Oil and Gas Evaluation Handbook and National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* and is based on the average forecast prices as at December 31, 2021 of three independent reserves evaluation firms. Additional information regarding reserves data and other oil and gas information is included in Headwater's Annual Information Form for the year ended December 31, 2021, dated March 10, 2022, which is available on the Company's website at and under the Company's profile on SEDAR at www.sedar.com.

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:

- expectation the weighted average annual discount to WCS to be approximately $2.50/bbl in 2022;
- expectation for the Company to be taxable in 2022 at current commodity pricing;
- business plans and strategies (including its production optimization and hedging strategies);
- the expectation that Headwater could make use of additional equity or debt financings to fund future acquisitions;
- 2022 guidance related to expected average daily production, capital expenditures, cash flows from operating activities, adjusted funds flow from operations, exit working capital and exit adjusted working capital;
- details of the 2022 approved capital expenditure budget including expected capital expenditures;
- exploration and development plans of Headwater and the expectation Headwater can fund its contractual obligations through existing working capital and cash flows provided by operating activities;
- 2022 crude oil and natural gas pricing assumptions; and
- 2022 Canadian – US dollar exchange rates.

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 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.

Any financial outlook or future oriented financial information in this press release, 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.

Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risks identified under the heading "*Business Conditions and Risks*". Further information regarding these factors and additional factors may be found under the heading "Risk Factors" in the Annual Informational Form for the year ended December 31, 2021, dated March 10, 2022, which is available on the Company's website at www.headwaterexp.com and under the Company's profile on SEDAR at www.sedar.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 & CEO, Headwater Exploration Inc.
Calgary, Alberta

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

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

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

PHILLIP KNOLL(3)
Director Altagas Ltd.
Calgary, Alberta

KEVIN OLSON (1) (3)
President, Camber Capital Corp. .
Calgary, Alberta

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

KAM SANDHAR (1)
Senior Vice-President, Conventional Cenovus Energy Inc.

Officers

NEIL ROSZELL, P. Eng.
Executive Chairman & CEO

JASON JASKELA, P. Eng.
President and COO

ALI HORVATH, CPA, CA
Vice President Finance & CFO

TERRY DANKU, P. Eng.
Vice President Engineering

JON GRIMWOOD, P. Geo.
Vice President Exploration

SCOTT RIDEOUT
Vice President Land

BRAD CHRISTMAN
Vice President Production

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

(1) Audit Committee
(2) Corporate Governance and Sustainability Committee
(3) Reserves Committee

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Auditors
KPMG LLP
Calgary, Alberta

Independent Reservoir Consultants
GLJ Ltd.