2020 Management's Discussion and Analysis

The following management's discussion and analysis ("MD&A") as provided by the management of Headwater Exploration Inc. (formerly Corridor Resources Inc.) ("Headwater" or the "Company") is dated March 10, 2021 and should be read in conjunction with the audited annual financial statements for the years ended December 31, 2020 and 2019 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. In addition, readers are also directed to the Company's Annual Information Form for the year ended December 31, 2020, dated March 10, 2021, 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.

On March 4, 2020, Headwater announced the completion of the Recapitalization Transaction (as defined herein), whereby the Company raised aggregate gross proceeds of $50 million pursuant to two equity private placements, a new management team was appointed and the Board of Directors of the Company was reconstituted. In addition, concurrently with the completion of the Recapitalization Transaction, the name of the Company was changed from "Corridor Resources Inc." to "Headwater Exploration Inc." and on March 9, 2020 the common shares of the Company commenced trading under the new symbol "HWX" on the Toronto Stock Exchange ("TSX").

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 2020 HIGHLIGHTS

- Closed the acquisition of Cenovus Energy Inc.'s position in the Marten Hills area of Alberta for estimated total consideration of $135.3 million. The acquired assets included a 100% working interest in approximately 2,800 barrels per day of heavy oil production and 270 net sections of Clearwater rights.

- Generated average production of 1,646 boe/d inclusive of one month of production from the acquired Marten Hills Assets.

- Achieved adjusted funds flow from operations(1) of $4.8 million ($0.03/share basic), representing a 150% increase from the fourth quarter of 2019. Cash flows used in operating activities were $1.5 million in the fourth quarter of 2020.

- Achieved an operating netback of $35.04/boe and an adjusted funds flow netback of $31.79/boe.

- Generated net income of $16.9 million ($0.10/share basic).

- As at December 31, 2020, Headwater had adjusted working capital (1) of $80.8 million and no outstanding debt.

YEAR ENDED DECEMBER 31, 2020

- Production averaged 882 boe/d for the year, an increase of 42% from 2019 annual production of 620 boe/d.
- Achieved adjusted funds flow from operations(1) of $8.8 million ($0.06/share basic). Cash flows from operating activities were $0.2 million for the year ended December 31, 2020.
- Achieved free cash flow(1) of $6.5 million.
- Proved developed producing reserves increased by 67% to 5.0 mmboe from 3.0 mmboe.
- Total proved reserves increased by 217% to 9.5 mmboe from 3.0 mmboe.
- Proved plus probable reserves increased 254% to 13.1 mmboe from 3.7 mmboe.
- Achieved finding, development and acquisition (“FD&A”) costs, including changes in future development costs of $26.89 per boe on a proved basis and $18.87 per boe on a proved plus probable basis.
- As at December 31, 2020, Headwater’s Liability Management Rating (“LMR”) was 31 in Alberta significantly exceeding the Alberta industry LMR average. Headwater remains committed to maintaining an LMR rating above the industry average and minimizing its environmental footprint.

(1) Non-IFRS measure. See “Non-IFRS Financial Measures” advisory.

Results of Operations

Operating netback

The components of Headwater’s operating netback for the three and twelve months ended December 31, 2020, for the Marten Hills assets and McCully assets are summarized below.

Marten Hills Assets

	Three months ended December 31, 2020	Three months ended December 31, 2019	Percent Change	Year ended December 31, 2020	Year ended December 31, 2019	Percent Change
	($/boe)			($/boe)		
Sales, net of blending (1)	45.05	-	100	45.05	-	100
Royalties	(6.01)	-	100	(6.01)	-	100
Transportation expense	(8.58)	-	100	(8.58)	-	100
Production expense	(6.77)	-	100	(6.77)	-	100
Operating netback (2)	23.69	-	100	23.69	-	100
Heavy oil production (bbls/d)	979	-	100	246	-	100

(1) Realized heavy oil prices are calculated based on sales, net of blending expense.
(2) Operating metric. See “Operating Metrics” advisory.
(3) In December 2020, WCS averaged Cdn$47.82/bbl.
(4) Reflects thirty days of operations from December 2, 2020 to December 31, 2020.

McCully Assets

	Three months ended December 31, 2020	2019	Percent Change	Year ended December 31, 2020	2019	Percent Change
	($/boe)			($/boe)		
Sales	36.29	42.84	(15)	21.91	41.24	(47)
Royalties	(0.70)	(0.96)	(27)	(0.49)	(1.02)	(52)
Production expense	(9.62)	(12.19)	(21)	(9.84)	(11.54)	(15)
Realized gain on financial derivatives	25.73	14.70	75	23.70	16.31	45
Operating netback	51.70	44.39	16	35.28	44.99	(22)
Natural gas and NGL production (boe/d)	667	586	14	636	620	3

Total Assets

	Three months ended December 31, 2020	2019	Percent Change	Year ended December 31, 2020	2019	Percent Change
	($/boe)			($/boe)		
Sales, net of blending	41.50	42.84	(3)	28.37	41.24	(31)
Royalties	(3.86)	(0.96)	302	(2.03)	(1.02)	99
Transportation expense	(5.10)	-	100	(2.40)	-	100
Production expense	(7.92)	(12.19)	(35)	(8.98)	(11.54)	(22)
Realized gain on financial derivatives	10.42	14.70	(29)	17.09	16.31	5
Operating netback	35.04	44.39	(21)	32.05	44.99	(29)
Average daily production (boe/d)	1,646	586	181	882	620	42

Production and pricing

	Three months ended December 31, 2020	2019	Percent Change	Year ended December 31, 2020	2019	Percent Change
Average daily production						
Heavy oil (bbls/d)	979	-	100	246	-	100
Natural gas (mmcf/d)	4.0	3.5	14	3.8	3.7	3
Natural gas liquids (bbls/d)	3	2	50	3	4	(25)
Barrels of oil equivalent (boe/d)	1,646	586	181	882	620	42
Headwater average sales price						
Heavy oil ($/bbl) (1)	45.05	-	100	45.05	-	100
Natural gas ($/mcf)	5.37	6.80	(21)	3.21	6.49	(51)
Natural gas liquids ($/bbl)	56.23	83.34	(33)	57.28	80.56	(29)
Barrels of oil equivalent ($/boe)	39.90	40.92	(2)	26.57	39.21	(32)
Average Benchmark Price						
WTI (US$/bbl) (2)	42.66	56.96	(25)	39.40	57.03	(31)
WCS differential to WTI (US$/bbl)	(9.30)	(15.83)	(41)	(12.60)	(12.76)	(1)
WCS (Cdn$/bbl) (3)	43.42	54.30	(20)	35.59	58.78	(39)
AGT (US$/mmbtu) (4)	2.74	3.19	(14)	2.00	3.17	(37)
NYMEX Henry Hub (US$/mmbtu)	2.66	2.50	6	2.08	2.63	(21)
Exchange rate (US$/Cdn$)	0.77	0.76	1	0.75	0.75	-

(1) Realized heavy oil prices are calculated based on sales, net of blending expense.
(2) WTI = West Texas Intermediate
(3) WCS = Western Canadian Select
(4) AGT = Algonquin city-gates

Sales

	Three months ended December 31, 2020	2019	Percent Change	Year ended December 31, 2020	2019	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Heavy oil	4,400	-	100	4,400	-	100
Natural gas	1,966	2,193	(10)	4,466	8,767	(49)
Natural gas liquids	17	13	31	54	107	(50)
Gathering, processing and transportation	243	104	134	579	459	26
Total sales	6,626	2,310	187	9,499	9,333	2
Blending expense	(343)	-	100	(343)	-	100
Total sales, net of blending expense	6,283	2,310	172	9,156	9,333	(2)

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

Headwater's heavy oil sales net of blending expense were $4,057 thousand in the fourth quarter of 2020, reflecting revenue earned from the Marten Hills Assets from the closing date of December 2, 2020 to December 31, 2020.

The Company sells its natural gas production daily from the McCully field in New Brunswick. The transaction price is based on the daily benchmark price Algonquin city-gates ("AGT") adjusted for the delivery location and heat content.

In recent years, 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. Headwater shut-in production May 1, 2020 and resumed operations October 30, 2020, pursuant to its production optimization strategy to time the start-up of production, and the associated recovery of flush volumes, with peak winter pricing to maximize cash flows from operations.

In the three months ended December 31, 2020, natural gas sales of $1,966 thousand were consistent with the comparable period of 2019 of $2,193 thousand. Headwater realized an average natural gas sales price of $5.37/mcf in the three months ended December 31, 2020, down 21% from the average price of $6.80/mcf realized for the fourth quarter of 2019. The decrease in Headwater's realized natural gas sales price was primarily due to above average temperatures in November and the first half of December 2020, resulting in decreased heating demand in the Northeastern United States. The impact of the decline in pricing was partially offset by an increase in production volumes to 4.0 mmcf/d in the fourth quarter of 2020 from 3.5 mmcf/d in the fourth quarter of 2019.

Natural gas sales for the year ended December 31, 2020 were $4,466 thousand compared to $8,767 thousand for the year ended December 31, 2019. The 49% decrease in natural gas sales is due to the significant decrease in Headwater's average realized natural gas sales price to $3.21/mcf in 2020 from $6.49/mcf realized in 2019, due to above average temperatures during the winter producing months putting downward pressure on AGT pricing. To mitigate the decline in natural gas prices in 2020, Headwater entered in financial derivative commodity contracts which resulted in significant realized gains of $5,515 thousand or $3.97/mcf. Inclusive of gains on financial derivatives, Headwater's average selling price at McCully for natural gas in 2020 was $7.18/mcf.

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

	Three months ended December 31, 2020	2019	Percent Change	Year ended December 31, 2020	2019	Percent Change
	(thousands of dollars)			(thousands of dollars)		
Realized financial derivative gains	1,578	793	99	5,515	3,691	49
Unrealized financial derivative gains (losses)	205	810	(75)	(1,407)	485	(390)
Financial derivative gains	1,783	1,603	11	4,108	4,176	(2)
Per boe	11.77	29.72	(60)	12.73	18.45	(31)

A key component of Headwater's production optimization strategy is to enter into financial derivative commodity contracts to mitigate the risks associated with the volatility of natural gas prices during the winter months when natural gas production from the McCully field occurs.

For the three months ended December 31, 2020, the Company recognized realized gains of $1,578 thousand on natural gas commodity contracts compared to $793 thousand in the corresponding period of 2019. The realized gain in the fourth quarter of 2020 is due to the unwinding and monetization of the following financial derivative commodity contracts:

Commodity	Index	Type	Term	Daily Volume	Contract Price
Natural Gas	NYMEX Henry Hub	Fixed	Dec 2020- Mar 2021	5,000 mmbtu/d	Cdn$4.05/mmbtu
Natural Gas	AGT differential (1)	Swap	Dec 2020- Mar 2021	5,000 mmbtu/d	Cdn$3.76/mmbtu
Natural Gas	AGT	Fixed	November 2020	2,500 mmbtu/d	Cdn$5.00/mmbtu

(1) Headwater pays on AGT while the counterparty pays on NYMEX plus Cdn $3.76/mmbtu.

For the year ended December 31, 2020 the Company realized significant financial derivative gains of $5,515 thousand compared to $3,691 thousand during the year ended December 31, 2019. The Company recognized gains on its natural gas contracts in both 2020 and 2019 as the commodity contracts to fix the NYMEX Henry Hub price and AGT price exceeded the settlement prices during the periods.

As of December 31, 2020, the fair value of Headwater's outstanding financial derivative commodity contracts is an unrealized asset of $74 thousand 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 receivable as at December 31, 2020, had the contracts been monetized or terminated. Subsequent changes in the fair value of the commodity contracts are recognized in each reporting period and could be materially different than what is recorded as at December 31, 2020.

As at December 31, 2020, Headwater had the following financial derivative contracts outstanding:

Commodity	Index	Type	Term	Daily Volume	Contract Price
Natural Gas	AGT	Fixed	Jan 1- Jan 31, 2021	7,500 mmbtu	Cdn $6.62/mmbtu
Natural Gas	AGT	Fixed	Feb 1- Feb 28, 2021	5,000 mmbtu	Cdn $6.50/mmbtu
Natural Gas	AGT	Fixed	Mar 1- Mar 31, 2021	5,000 mmbtu	Cdn $4.61/mmbtu

Subsequent to December 31, 2020, the Company entered into WCS-WTI differential commodity contracts in relation to the newly acquired Marten Hills Assets and additional natural gas commodity contracts. Refer to the heading "Subsequent Events".

Royalty Expense

	Three months ended December 31, 2020	2019	Percent Change	Year ended December 31, 2020	2019	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Heavy oil	541	-	100	541	-	100
Natural gas and natural gas liquids	43	52	(17)	115	230	(50)
Total royalty expense	584	52	1023	656	230	185
Percentage of sales	8.8%	2.3%	283	6.9%	2.5%	176
Per boe ($)	3.86	0.96	302	2.03	1.02	99

Royalty expense consists of crown royalties payable to the Alberta and New Brunswick provincial governments and the gross overriding royalty ("GORR") payable to Cenovus.

Royalty expense incurred on the natural gas properties for the three and twelve months ended December 31, 2020, were $43 thousand and $115 thousand respectively, compared to $52 thousand and $230 thousand in the corresponding periods of 2019, primarily due to a significant decline in realized natural gas pricing.

Headwater's average royalty rate was 6.9% during 2020 compared to an average royalty rate of 2.5% in 2019, reflecting crown and GORR royalties incurred on the Marten Hills Assets following the close of the Acquisition on December 2, 2020.

Blending and Transportation Expense

	Three months ended December 31, 2020	2019	Percent Change	Year ended December 31, 2020	2019	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Blending and transportation expense	1,115	-	100	1,115	-	100
Per boe ($)	7.37	-	100	3.46	-	100

Blending expense includes the cost of blending diluent purchased in order to reduce the viscosity of the Company's heavy oil transported through pipelines to meet pipeline specifications. Transportation expense includes clean oil trucking, terminal fees and pipeline tariffs incurred to move production to the sales point.

For both the three months and twelve months ended December 31, 2020, blending and transportation expense increased to $1,115 thousand as a result of blending and transportation costs incurred with the respect to the Company's heavy oil sales following the close of the Acquisition on December 2, 2020.

Production Expense

	Three months ended December 31, 2020	2019	Percent Change	Year ended December 31, 2020	2019	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Production expense	1,199	657	82	2,899	2,611	11
Per boe ($)	7.92	12.19	(35)	8.98	11.54	(22)

Production expenses in the three and twelve months ended December 31, 2020, were $1,199 thousand and $2,899 thousand, respectively, compared to $657 thousand and $2,611 thousand in the corresponding periods of 2019. The increase in production expenses in 2020 reflects production costs incurred on the Company's Marten Hills Assets following the close of the Acquisition on December 2, 2020.

Production expenses on Headwater's McCully assets in the three and twelve months ended December 31, 2020, were $590 thousand and $2,290 thousand, respectively, compared to $657 thousand and $2,611 thousand in the corresponding periods of 2019. The decrease in production expenses in 2020 is attributed to cost savings initiatives including restructuring the Company's joint venture agreement which increased production recoveries during the year.

Production expenses per boe decreased in both the three and twelve months ended December 31, 2020, averaging $7.92 per boe and $8.98 per boe, respectively, from $12.19 per boe and $11.54 per boe in the corresponding periods of 2019. The decrease in production costs per boe reflects the integration of the Marten Hills Assets acquired at a lower average cost per boe combined with operational cost savings initiatives in McCully.

General and Administrative ("G&A") Expenses

	Three months ended December 31,		Percent	Year ended December 31,		Percent
	2020	2019	Change	2020	2019	Change
	(thousands of dollars)			*(thousands of dollars)*		
G&A expenses - recapitalization	-	-	-	278	-	100
G&A expenses	703	713	(1)	2,557	3,002	(15)
Net G&A expenses	703	713	(1)	2,835	3,002	(6)
Per boe ($)	4.64	13.22	(65)	8.78	13.26	(34)

G&A expenses, excluding incremental recapitalization costs, for the three months and year ended December 31, 2020 were $703 thousand and $2,557 thousand, respectively, compared to $713 thousand and $3,002 thousand recorded in the corresponding periods of 2019. G&A expenses, excluding incremental recapitalization costs, are lower for the year ended December 31, 2020 compared to the year ended December 31, 2019 primarily due to the Canadian federal government's Canada Emergency Wage Subsidy ("CEWS") program. Under the CEWS program, Canadian employers affected by COVID-19 can apply for a subsidy for eligible employees provided that certain criteria are met. In 2020, a total of $439 thousand was claimed by the Company under the CEWS program of which $298 thousand was recorded as a recovery in G&A expense and $141 thousand related to field employees as a recovery in production expenses.

Recapitalization costs were $278 thousand for the year ended December 31, 2020. These expenses were incurred to facilitate the integration of east coast operations with the Company's new head office in Calgary following the Recapitalization Transaction. These costs include legal fees, consulting fees and additional software and IT-related fees.

Transaction Costs

	Three months ended December 31, 2020	2019	Percent Change	Year ended December 31, 2020	2019	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Transaction costs	2,948	-	100	7,330	-	100
Per boe ($)	19.47	-	100	22.71	-	100

For the three months ended December 31, 2020, the Company incurred transaction costs of $2,948 thousand to complete the Acquisition that closed on December 2, 2020. These costs primarily consist of advisory and legal fees.

For the year ended December 31, 2020, Headwater incurred transaction costs of $7,330 thousand of which $4,382 thousand were incurred pursuant to the Recapitalization Transaction and $2,948 were incurred to complete the Acquisition. Costs incurred pursuant to the Recapitalization Transaction consist primarily of severance, advisory and legal fees.

Interest Income and Other

	Three months ended December 31, 2020	2019	Percent Change	Year ended December 31, 2020	2019	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Interest income	236	296	(20)	1,144	1,147	-
Foreign exchange gains (losses)	(24)	(40)	(40)	129	(83)	(255)
Accretion	(32)	(50)	(36)	(149)	(219)	(32)
Interest on lease liability	-	(1)	(100)	(11)	(15)	(27)
Total interest income and other	180	205	(12)	1,113	830	34
Per boe ($)	1.19	3.80	(69)	3.45	3.67	(6)

Interest income and other was lower during the three months ended December 31, 2020 when compared to the same period in the prior year primarily due to lower interest income as a result of lower interest rates throughout the quarter. 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. This decline in interest rates was partially offset by a higher average cash and cash equivalents balance on hand throughout the quarter as a result of the closing of the non-brokered and brokered private placements on March 4, 2020 for aggregate gross proceeds of $50 million.

Interest income and other was higher during the year ended December 31, 2020 when compared to the year ended December 31, 2019 primarily due to foreign exchange gains of $129 thousand in 2020 compared to foreign exchange losses of $83 thousand in 2019. Realized foreign exchange gains and losses will vary depending on the fluctuation in the exchange rate between the timing of US dollar denominated sales incurred and the timing of the settlement of the underlying receivable. Interest income remained flat year over year as the decline in interest rates was offset by a higher average cash and cash equivalents balance throughout the year.

Remeasurement Loss on Warrant Liability

	Three months ended December 31, 2020	2019	Percent Change	Year ended December 31, 2020	2019	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Remeasurement loss on warrant liability	4,289	-	100	4,289	-	100
Per boe ($)	28.33	-	100	13.29	-	100

During the three months and year ended December 31, 2020, the Company recognized a remeasurement loss on its warrant liability of $4,289 thousand.

The warrant liability recognized on the Acquisition is a result of the 15 million warrants issued to Cenovus as partial consideration for the Acquired Assets. The warrants have an exercise price of $2.00 and expire on the third anniversary of the Closing Date. Headwater has the right, after twelve months have elapsed from the Closing Date and provided the 20-day volume weighted average share price of the Company's common shares exceeds the exercise price of the warrants, to require Cenovus to exercise all or a portion of the then-outstanding warrants. The warrants issued were classified as a financial liability as a result of a cashless exercise provision and are therefore carried at fair value through profit or loss. In no event will the Company be required to settle the warrants through a cash payment.

The warrants are revalued every reporting period using a Monte Carlo simulation pricing model. The Company recognized a remeasurement loss of $4,289 thousand as a result of the increase in the Company's closing common share price to $2.39 on December 31, 2020 from $1.93 on December 2, 2020.

Stock-based Compensation

	Three months ended December 31, 2020	2019	Percent Change	Year ended December 31, 2020	2019	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Stock options	538	71	658	1,414	326	334
Deferred share units	37	32	16	63	11	473
Stock-based compensation expense	575	103	458	1,477	337	338
Per boe ($)	3.80	1.90	100	4.58	1.49	207

Stock-based compensation, with respect to stock options, was higher when compared to the same periods in the prior year as a result of the 7,905 thousand stock options granted during the year to directors, officers and employees of the Company. The stock options granted had a weighted average fair value of $0.61 per stock option estimated using the Black Scholes option pricing model.

Stock-based compensation relating to deferred share units ("DSUs") 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. During the year ended December 31, 2020, a total of $535 thousand was paid out on the redemption of the DSUs pursuant to the Recapitalization Transaction and the reconstitution of the Board of Directors.

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 TSX on the trading day prior to the date the option was granted. Options granted under the Old Option Plan generally vest 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 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 will vest as to one third of the number of options granted on each of the first, second and third anniversaries of the date of grant, respectively, 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. In accordance with IFRS 2, stock options previously granted under the New Option Plan were revalued on June 15, 2020.

As at December 31, 2020 there were 1,272,502 stock options outstanding under the Old Option Plan and 6,705,000 stock options outstanding under the New Option Plan.

Depletion & Depreciation

	Three months ended December 31,		Percent Change	Year ended December 31,		Percent Change
	2020	2019		2020	2019	
	(thousands of dollars)			*(thousands of dollars)*		
Depletion	2,540	1,298	96	5,637	4,460	26
Depreciation	46	77	(40)	258	302	(15)
Depletion & depreciation	2,586	1,375	88	5,895	4,762	24
Depletion - Per boe ($)	16.78	24.08	(30)	17.46	19.70	(11)
Depreciation – Per boe ($)	0.30	1.42	(79)	0.80	1.34	(40)
Total – Per boe ($)	17.08	25.50	(33)	18.26	21.04	(13)

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. Concurrent with the closing of the Acquisition, management changed the basis of reserves used in its depletion calculation of the McCully assets from proved reserves to proved plus probable reserves before royalties as this is more aligned with the basis management uses to assess the business. A change in the basis of reserves constitutes a change in accounting estimate under IAS 8 with the effect of the change recognized prospectively. The change in estimate resulted in a decrease of depletion expense of $112 thousand recorded for the year ended December 31, 2020.

Depletion for the three months and twelve months ended December 31, 2020 was $2,540 thousand and $5,637 thousand, respectively, compared to $1,298 thousand and $4,460 thousand recorded in the corresponding periods of 2019. This increase is primarily a result of depletion of $1,618 thousand recorded for the Company's Marten Hills Assets following the close of the Acquisition on December 2, 2020.

Depletion per boe decreased in both the three and twelve months ended December 31, 2020 due to the Marten Hills Assets acquired at a lower cost per boe combined with an increase in proved plus probable natural gas reserves as a result of improved recovery and technical revisions in the McCully field.

Exploration and Evaluation Expense

Since May 27, 2016, the Company's McCully assets in New Brunswick have been subject to a moratorium on hydraulic fracturing. There is significant uncertainty regarding the ultimate realization of the value of the E&E assets as all undeveloped wells in the McCully field require hydraulic fracture stimulation to be commercially productive. Accordingly, in March 2020, the Company recorded exploration and evaluation expense of $3,821 thousand.

The Company concluded there are no indicators of impairment for its E&E assets at December 31, 2020.

Impairment Reversal

	Three months ended December 31,		Percent Change	Year ended December 31,		Percent Change
	2020	2019		2020	2019	
	(thousands of dollars)			*(thousands of dollars)*		
Impairment reversal	(15,054)	(322)	4575	(15,054)	(322)	4575
Per boe ($)	(99.43)	(5.97)	1565	(46.64)	(1.42)	3185

For the year ended December 31, 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 $15,054 thousand.

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 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
	$ thousands
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)

For the year ended December 31, 2019, due to an increase in proved plus probable natural gas reserves, the Company determined an indicator of potential impairment reversal was present for its New Brunswick CGU. As a result, the Company completed an impairment reversal test and recorded a recovery of $322 thousand.

Indicators of Impairment – Alberta CGU

The Company concluded there are no indicators of impairment for its Alberta CGU at December 31, 2020.

Decommissioning Liabilities

As at December 31, 2020, the decommissioning liabilities of the Company were $16,718 thousand compared to $11,976 thousand at December 31, 2019. The total future undiscounted amount of estimated cash flows required to settle these obligations is $23,611 thousand (December 31, 2019 – $16,998 thousand). Management estimates the settlement of these obligations will occur over the next 17 to 32 years. As at December 31, 2020, a risk-free rate of 1.2% (December 31, 2019 – 1.8%) and an inflation rate of 1.5% (December 31, 2019 – 2.0%) were used to calculate the estimated fair value of the decommissioning liability.

The total uninflated and undiscounted amount of estimated cash flows required to settle the Company's decommissioning liabilities is $15,456 thousand.

The undiscounted amount of decommissioning liabilities acquired pursuant to the Acquisition is estimated to be approximately $3,756 thousand ($4,814 thousand inflated at 1.5%). The fair value of decommissioning liabilities acquired of $1,709 thousand was estimated by discounting the inflated cost estimates using a credit-adjusted risk-free rate of 6.3% on the Closing Date. The obligations acquired were subsequently remeasured in accordance with the Company's accounting policy, whereby decommissioning liabilities are discounted using a risk-free rate. Remeasurement of the decommissioning liabilities acquired at a risk-free rate of 1.2%, resulted in an increase in the present value of decommissioning liabilities acquired by $2,228 thousand.

Deferred Income Taxes

	Three months ended December 31,		Percent Change	Year ended December 31,		Percent Change
	2020	2019		2020	2019	
	thousands of dollars			*thousands of dollars*		
Deferred income tax expense (recovery)	(7,277)	(58)	12447	(7,277)	753	(1066)
Canadian statutory income tax rate	26.3%	29.0%	(9)	26.3%	29.0%	(9)

For the three and twelve months ended December 31, 2020, the Company recorded a deferred income tax recovery of $7,277 thousand compared to a deferred income tax recovery of $58 thousand for the three months ended December 31, 2019 and deferred income tax expense of $753 thousand for the twelve months ended December 31, 2019. The Company's effective tax provision rate in 2020 is 26.3%.

At December 31, 2020, the Company had approximately $263.4 million of tax pools available to be applied against future taxable income. The federal tax pools are estimated as follows:

($ thousands)	Estimated balance at December 31, 2020
Canadian oil and gas property expense	74,522
Canadian development expense	22,775
Canadian exploration expense	101,920
Undepreciated capital cost	31,790
Non-capital losses (1)	26,028
Other	6,325
Total	263,360

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

Adjusted Funds Flow from Operations and Net Income

For the year ended December 31, 2020, Headwater's net income increased to $6,707 thousand from $2,815 thousand for the year ended December 31, 2019 due primarily to a PP&E impairment reversal of $15,054 thousand and a deferred income tax recovery of $7,277 thousand that were partially offset by transaction costs of $7,330 thousand and the remeasurement loss of $4,289 thousand on the warrant liability.

Adjusted funds flow from operations of $8,782 thousand for the year ended December 31, 2020 is slightly higher when compared to adjusted funds flow from operations for the year ended December 31, 2019 of $8,206 thousand. The decline in natural gas sales in 2020 due to lower average realized natural pricing was offset by December heavy oil sales generated from the newly acquired Marten Hills Assets. Additionally, realized gains on financial derivatives were higher by $1,824 thousand for the year ended December 31, 2020. Cash flows from operating activities decreased to $230 thousand for the year ended December 31, 2020 from $8,861 thousand for the year ended December 31, 2019 mainly due to transaction costs of $7,330 thousand.

The following table summarizes the operating netback, adjusted funds flow netback and net income on a barrel of oil equivalent basis:

	Three months ended December 31, 2020	Three months ended December 31, 2019	Percent Change	Year ended December 31, 2020	Year ended December 31, 2019	Percent Change
	($/boe)			($/boe)		
Sales	43.77	42.84	2	29.43	41.24	(29)
Realized gains on financial derivatives	10.42	14.70	(29)	17.09	16.31	5
Royalties	(3.86)	(0.96)	302	(2.03)	(1.02)	99
Net sales	50.33	56.58	(11)	44.49	56.53	(21)
Blending and transportation	(7.37)	-	100	(3.46)	-	100
Production expense	(7.92)	(12.19)	(35)	(8.98)	(11.54)	(22)
Operating netback (1)	35.04	44.39	(21)	32.05	44.99	(29)
General and administrative expenses	(4.64)	(13.22)	(65)	(8.78)	(13.26)	(34)
Interest income and other (2)	1.39	4.73	(71)	3.94	4.64	(15)
Decommissioning liabilities settled	-	(0.13)	(100)	-	(0.11)	(100)
Adjusted funds flow netback (1)	31.79	35.77	(11)	27.21	36.26	(25)
Transaction costs	(19.47)	-	100	(22.71)	-	100
Remeasurement loss on warrant liability	(28.33)	-	100	(13.29)	-	100
Unrealized gains (losses) on financial derivatives	1.35	15.02	(91)	(4.36)	2.14	(304)
Stock-based compensation expense	(3.80)	(1.90)	100	(4.58)	(1.49)	207
Decommissioning liabilities settled	-	0.13	(100)	-	0.11	(100)
Depletion and depreciation	(17.08)	(25.50)	(33)	(18.26)	(21.04)	(13)
Accretion and other expense	(0.20)	(0.93)	(78)	(0.49)	(0.97)	(49)
Impairment reversal	99.43	5.97	1565	46.64	1.42	3185
Exploration and evaluation expense	-	-	-	(11.84)	-	100
Other write-downs and losses	-	(2.80)	(100)	(0.08)	(0.67)	(88)
Income (loss) before income taxes	63.69	25.76	147	(1.76)	15.76	(111)
Deferred income tax recovery (expense)	48.06	1.08	4350	22.54	(3.33)	(777)
Net income	111.75	26.84	316	20.78	12.43	67

(1) Operating metric. See "Operating Metrics" advisory.
(2) Excludes accretion on decommissioning liabilities and interest on lease liability.

Capital Expenditures

	Three months ended December 31, 2020	Three months ended December 31, 2019	Percent Change	Year ended December 31, 2020	Year ended December 31, 2019	Percent Change
	(thousands of dollars)			(thousands of dollars)		
Lease acquisition and retention	-	-	-	293	-	100
Geological and geophysical	82	33	148	175	450	(61)
Drilling and completions	1,646	-	100	1,646	-	100
Pipeline infrastructure	(3)	191	(102)	108	191	(43)
Corporate	23	3	667	55	44	25
Development capital expenditures	1,748	227	670	2,277	685	232
Property acquisition	135,297	-	100	135,297	-	100
Capital expenditures	137,045	227	60,272	137,574	685	19,984

Development capital expenditures were $1,748 thousand for the three months ended December 31, 2020 and $2,277 thousand for the year ended December 31, 2020 compared to $227 thousand and $685 thousand in the corresponding periods of the prior year. Capital expenditures incurred in 2020 primarily relate to site preparation and pre-drilling costs incurred on the newly acquired Marten Hills Assets in anticipation of the 2021 drilling program.

Marten Hills Property Acquisition

On November 8, 2020, the Company entered into a purchase and sale agreement with Cenovus with respect to Acquisition. The Acquisition was completed on December 2, 2020 (the "Closing Date") for estimated total consideration of $135.3 million, comprised of $32.8 million of cash (inclusive of interim adjustments), $96.5 million of common shares valued using Headwater's closing share price on the Closing Date and $6.0 million attributed to the warrants. The warrants have a three-year term and an exercise price of $2.00 per common share. The effective date of the Acquisition is October 1, 2020.

The acquired Marten Hills Assets include 100% working interest in Marten Hills heavy oil properties (average 18 - 22˚ API) and 270 net sections of Clearwater rights. Cenovus retained a GORR on the Marten Hills Assets. In connection with the completion of the Acquisition, Headwater entered into a development agreement ("Development Agreement") with Cenovus on the Closing Date, under which the Company committed to spend $100 million in expenditures on the Marten Hills Assets by December 31, 2022 unless otherwise extended by Cenovus. The Company also assumed certain transportation commitments from Cenovus. Refer to heading "Contractual Obligations and Commitments" for additional information.

2021 Capital Budget

Headwater's Board of Directors has approved a revised capital expenditures budget of $90 to $95 million for the year ended December 31, 2021. Headwater has allocated $60 million to the development of producing wells, injection wells and source wells, $25 to $30 million to facility infrastructure and $5 million to land and seismic. The Company expects to fund its planned 2021 capital expenditures through existing working capital and estimated 2021 adjusted funds flow from operations of $90 to $95 million. The Company does not plan to incur any significant capital expenditures in New Brunswick while the moratorium on hydraulic fracturing remains in place.

Guidance

A summary of the guidance that was provided by the Company in March 2020 relating to the McCully assets compared to the actual results from 2020, are as follows:

	2020 Guidance	2020 Actuals
Production (mmcf/d)	4.1	3.8
Operating cash flow (1)	$6.8 million	$8.2 million
Capital expenditures	$0.5 million	$0.1 million

(1) Non-IFRS measure. See "Non-IFRS Financial Measures" advisory.
(2) Guidance announced in March 2020 was provided prior to the Acquisition.

McCully natural gas production was in line with 2020 guidance. Operating cash flow of $8.2 million was higher than guidance by $1.4 million primarily due to the monetization of financial derivatives on commodity contracts resulting in cash proceeds of $1.6 million.

Adjusted working capital as at December 31, 2020 was $80.8 million compared to working capital guidance of $115 million. The decrease in working capital is primarily due to the $32.8 million cash consideration paid in connection with the Acquisition. Adjusted funds flow from operations for the twelve months ended was $8.8 million which exceeded guidance primarily due to operating cash flow generated on the Marten Hills Assets.

The following table summarizes Headwater's revised 2021 guidance compared to what was previously released on December 15, 2020.

	2021 Guidance	Revised 2021 Guidance
Average Daily Production		
Barrels of oil equivalent (boe/d)	6,500 - 7,000	6,500 – 7,000
Fourth quarter 2021 daily production (boe/d)	8,000 - 8,500	8,000 – 8,500
Pricing		
Crude oil - WTI (US$/bbl)	45.00	62.65
Crude oil - WCS (Cdn$/bbl)	40.40	63.75
Exchange rate (US$/Cdn$)	0.78	0.79
Natural gas - AGT (US$/mmbtu) (1)	4.41	4.36
Key Assumptions		
Adjusted funds flow netback ($/boe)	19.50 - 20.50	36.60
Financial Summary ($millions)		
Capital expenditures	85 - 90	90 - 95
Adjusted funds flow from operations (2)	48 - 52	90 - 95
Estimated exit adjusted working capital surplus (2)	45	80

(1) The AGT price is the average for the winter producing months in the McCully field which include January – April 2021 and November – December 2021.
(2) Non-IFRS measure. See "Non-IFRS Financial Measures" advisory. Exit working capital surplus has been revised to exit adjusted working capital surplus.

Liquidity and Capital Resources

Headwater's liquidity depends on the Company's cash flows from operations, supplemented as necessary by equity and debt financings. The Company raised aggregate gross proceeds of $50 million through the closing of its non-brokered and brokered private placements on March 4, 2020. The Company closed the Acquisition on December 2, 2020 by issuing 50 million common shares and 15 million warrants combined with a cash payment of $32.8 million.

At December 31, 2020, the Company had cash and cash equivalents of $76,772 thousand, an adjusted working capital surplus of $80,759 thousand and no outstanding debt. Given the Company's available liquid resources and Headwater's 2021 budget, management expects to have sufficient available funds through existing working capital and forecasted cash flows from operations to meet planned capital expenditures and contractual obligations in the near term.

Contractual Obligations and Commitments

The following table details the contractual maturities of the Company's financial liabilities as at December 31, 2020:

	Within 1 year	1 to 5 years
	$	$
Accounts payable and accrued liabilities	4,105	-
DSU liability	91	-
Lease liability	138	298
Total	4,334	298

As at December 31, 2020, the Company is committed to future payments under the following agreements:

	Total	2021	2022	2023	2024	2025	Thereafter
	$	$	$	$	$	$	$
Transportation (1)	110,766	7,419	9,038	10,691	10,905	11,982	60,731
Capital commitment (2)	100,000	-	100,000	-	-	-	-
Total (3)	210,766	7,419	109,038	10,691	10,905	11,982	60,731

(1) In connection with the completion of the Acquisition, Headwater assumed certain transportation contracts from Cenovus. Subsequent to the closing of the transaction, Headwater elected into the following obligations:
   a. 10- year take-or-pay transportation agreement with a minimum volume commitment of 10,000 boe/d.
   b. 10- year financial commitment at $1,890 thousand per year adjusted for inflation.
   c. 10-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) In connection with the completion of the Acquisition, Headwater entered into a Development Agreement with Cenovus on the Closing Date, under which the Company committed to spend $100 million in capital expenditures on the Marten Hills Assets by December 31, 2022 unless otherwise extended by Cenovus. The Company agreed that if it fails to satisfy the expenditures prior to December 31, 2022, the Company will pay to Cenovus the balance of any remaining expenditures and Headwater will have no further expenditures under the Development Agreement.

(3) Excludes leases accounted for under IFRS 16.

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,	
	2020	2019	2020	2019
Weighted average outstanding common shares (1)				
-Basic	161,365	88,147	139,379	88,472
-Diluted	168,600	88,542	145,377	88,757
Outstanding securities at December 31, 2020				
-Common shares				195,106
-Stock options – weighted average strike price of $1.32				7,978
-Warrants – strike price of $0.92 (2)				21,677
-Warrants issued to Cenovus – strike price of $2.00 (3)				15,000

(1) The Company uses the treasury stock method to determine the dilutive effect of stock options, Warrants and the warrants issued to Cenovus as partial consideration for the Acquisition. 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 part of the non-brokered private placement. As at December 31, 2020, these Warrants are fully exercisable with a strike price of $0.92.

(3) Issued on the Acquisition as partial consideration for the Marten Hills Assets. As at December 31, 2020, these warrants are fully exercisable with a strike price of $2.00.

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 vest and become 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 of Directors 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 of Directors 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.

Acquisition

Headwater issued 50 million common shares to Cenovus as part of the consideration for the Marten Hills Assets. The common shares were fair valued on the Closing Date of the Acquisition using Headwater's closing share price which was $1.93 per share.

Normal Course Issuer Bid ("NCIB")

During the year ended December 31, 2019, the Company purchased and cancelled 777 thousand common shares for total consideration of $549 thousand. The total cost paid, including commissions and fees, was recognized directly as a reduction in shareholders' equity. Under the NCIB, all common shares purchased were cancelled.

On August 23, 2018, the Company implemented a NCIB pursuant to the rules of the TSX that allowed the Company to purchase, for cancellation, up to 6,803,118 common shares. The NCIB expired on August 22, 2019.

Total Market Capitalization

The Company's market capitalization at December 31, 2020 was approximately $466.3 million.

(thousands)	December 31, 2020
Common shares outstanding	195,106
Share price (1)	$2.39
Total market capitalization	$466,303

(1) Represents the last price traded on the TSX on December 31, 2020.

As at March 10, 2021 the Company had 195,410,957 common shares outstanding.

(thousands)	March 10, 2021
Outstanding securities at March 10, 2021	
-Common shares	195,411
-Stock options – weighted average strike price of $1.44	8,621
-Warrants – strike price of $0.92	21,424
-Warrants issued to Cenovus – strike price of $2.00	15,000

Related Party Transactions

Key management personnel of the Company include its directors and senior management. In 2020, the Company recorded $2,914 thousand (2019 – $1,228 thousand) relating to compensation of key management personnel. In 2020, stock-based compensation expense relating to compensation of key management personnel was $1,260 thousand (2019 – $232 thousand).

Transactions with Cenovus

As at December 31, 2020, Cenovus owned 25.6% of the Company's basic common shares outstanding and two of its senior officers serve as directors of Headwater. In connection with the Acquisition, Headwater and Cenovus entered into a marketing agreement. Headwater considers the marketing agreement to be at market terms and in the ordinary course of business. The contract terminates on December 2, 2023. As at December 31, 2020, a receivable of $3.7 million was recorded from Cenovus for December heavy oil sales net of blending costs, certain transportation costs and royalties. Additionally, Cenovus retained a GORR on the Marten Hills Assets and the Company has a capital commitment under which Headwater is committed to spend $100 million in capital expenditures on the Marten Hills Assets by December 31, 2022 pursuant to the Development Agreement.

Selected Annual Financial Information

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

	2020	2019	2018
(thousands of dollars except share data and production volumes)			
Average production volumes (boe/d)	882	620	709
Sales	9,499	9,333	16,944
Net income (loss)	6,707	2,815	(314)
Net income (loss) per share			
-basic	0.05	0.03	-
-diluted	0.05	0.03	-
Cash flows provided by operating activities	230	8,861	10,115
Adjusted funds flow from operations (1)	8,782	8,206	10,232
Adjusted working capital (1)	80,759	63,141	56,194
Development capital expenditures	2,277	685	2,254
Property acquisition	135,297	-	-
Total assets	300,685	128,271	125,326

(1) Non-IFRS financial measures. See "Non-IFRS Financial Measures" advisory.

Summary of Quarterly Information

	Q4/20	Q3/20	Q2/20	Q1/20	Q4/19	Q3/19	Q2/19	Q1/19
Financial *(thousands of dollars except share data)*								
Sales	6,626	-	565	2,308	2,310	-	1,014	6,009
Cash flows provided by (used in) operating activities [5]	(1,451)	(364)	863	1,182	(192)	(342)	1,675	7,720
Adjusted funds flow from (used in) operations [1] [5]	4,816	(837)	(610)	5,413	1,929	(1,427)	151	7,554
Per share - basic	0.03	(0.01)	-	0.05	0.02	(0.02)	-	0.08
- diluted	0.03	(0.01)	-	0.05	0.02	(0.02)	-	0.08
Net income (loss)	16,919	(1,723)	(1,679)	(6,810)	1,447	(1,318)	(274)	2,960
Per share - basic	0.10	(0.01)	(0.01)	(0.06)	0.02	(0.02)	-	0.03
- diluted	0.10	(0.01)	(0.01)	(0.06)	0.02	(0.02)	-	0.03
Development capital expenditures	1,748	61	398	70	227	69	211	178
Property acquisition	135,297	-	-	-	-	-	-	-
Adjusted working capital [1]	80,759	112,667	113,569	114,200	63,141	61,388	62,937	63,464
Shareholders' equity	269,030	155,148	156,386	157,235	114,310	112,792	114,148	114,768
Weighted average shares *thousands)*								
Basic	161,365	145,044	144,749	105,436	88,147	88,172	88,724	88,919
Diluted	168,600	145,044	144,749	105,436	88,542	88,172	88,724	89,213
Shares outstanding, end of period *(thousands)*								
Basic	195,106	145,044	145,044	144,327	88,147	88,147	88,301	88,924
Diluted [7]	238,121	158,627	151,381	145,552	89,842	88,935	89,089	90,430
Operating *(6:1 boe conversion)*								
Average daily production								
Heavy oil (*bbls/d*)	979	-	-	-	-	-	-	-
Natural gas *(mmcf/d)*	4.0	-	2.4	8.9	3.5	-	2.4	9.0
Natural gas liquids *(bbls/d)*	3	-	-	7	2	-	3	10
Barrels of oil equivalent *(boe/d)* [2]	1,646	-	396	1,487	586	-	401	1,510
Average selling prices [3]								
Heavy oil (*$/bbl*)	45.05	-	-	-	-	-	-	-
Natural gas *($/mcf)*	5.37	-	2.27	2.49	6.80	-	4.16	7.00
Natural gas liquids *($/bbl)*	56.23	-	-	57.90	83.34	-	89.82	76.81
Barrels of oil equivalent *($/boe)* [2]	39.90	-	13.63	15.12	40.92	-	25.49	42.22
Netbacks ($/boe) [2]								
Operating								
Sales [3]	43.77	-	15.67	17.06	42.84	-	27.75	44.23
Realized gain on financial derivates	10.42	-	-	29.09	14.70	-	1.43	20.95
Royalties	(3.86)	-	(0.39)	(0.42)	(0.96)	-	(0.53)	(1.17)
Blending and transportation	(7.37)	-	-	-	-	-	-	-
Production expense	(7.92)	-	(14.79)	(4.78)	(12.19)	-	(16.64)	(5.50)
Operating netback *($/boe)* [4]	35.04	-	0.49	40.95	44.39	-	12.01	58.51
General and administrative	(4.64)	-	(23.33)	(5.05)	(13.22)	-	(15.89)	(4.43)
Interest income and other [6]	1.39	-	6.00	4.10	4.73	-	8.46	1.49
Decommissioning liabilities settled	-	-	-	-	(0.13)	-	(0.44)	(0.03)
Adjusted funds flow netback *($/boe)* [4][5]	31.79	-	(16.84)	40.00	35.77	-	4.14	55.54

(1) Non-IFRS measure. See "Non-IFRS Financial Measures" advisory.
(2) See barrels of oil equivalent under "Oil and Gas Measures".
(3) Excludes realized and unrealized gains (losses) on financial derivative commodity contracts.
(4) Operating metric. See "Operating Metrics" advisory.
(5) Comparative period revised to reflect current period presentation. Decommissioning liabilities settled was previously not included in cash flows from operations, adjusted funds flow from operations or the adjusted funds flow netback calculation.
(6) Excludes accretion on decommissioning liabilities and interest on the lease liability.
(7) Includes in-the-money dilutive instruments as at December 31, 2020 which include 6.3 million stock options with a weighted average exercise price of $1.04, 21.7 million Warrants with an exercise price of $0.92 and 15 million warrants issued to Cenovus with an exercise price of $2.00.

On December 2, 2020, Headwater closed the Acquisition which added $4,400 thousand of heavy oil sales for the three months ended December 31, 2020. Additionally, the Company incurred $2,948 thousand of transaction costs to complete the Acquisition. Headwater generated net income of $16,919 in the fourth quarter of 2020 primarily due to PP&E impairment reversal of $15,054 thousand related to the McCully CGU and a deferred income tax recovery of $7,277 thousand.

In Q3 2020, Headwater incurred a net loss of $1,723 thousand. There were no sales recognized in the quarter as the Company shut-in production pursuant to its production optimization strategy. The Company resumed McCully operations in late October 2020.

In Q2 2020, Headwater incurred a net loss of $1,679 thousand due primarily to lower natural gas sales attributed to a lower average realized natural gas sales price, higher stock-based compensation associated with stock option grants to directors, officers and employees of Headwater and higher general and administrative costs as a result of the Recapitalization Transaction and transitioning the head office from Halifax to Calgary.

In Q1 2020, Headwater incurred a net loss of $6,810 thousand due primarily to transaction costs of $4,382 thousand incurred pursuant to the Recapitalization Transaction, exploration and evaluation expense of $3,821 thousand and lower natural gas sales attributed to a lower average realized natural gas sales price.

Headwater's 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. A key component of this production optimization strategy is to enter into financial hedges to mitigate the risks associated with the volatility of natural gas prices when natural gas production resumes.

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) Stock option grant

Subsequent to December 31, 2020, Headwater granted 710 thousand stock options to new employees of the Company under the New Option Plan.

In addition, at the meeting of the Board of Directors held on March 10, 2021, the Directors approved a total grant of up to 2,300,000 stock options to Directors, management and employees under the New Option Plan.

b) Financial derivative commodity contracts and foreign exchange contract

Subsequent to December 31, 2020, Headwater entered into the following financial derivative contracts:

Commodity	Index	Type	Term	Daily Volume	Contract Price
Heavy Oil	WCS differential (1)	Fixed	Oct 2021 - Dec 2021	2,000 bbls/d	US$13.16/bbl
Natural Gas	AGT	Fixed	Feb 2 – Feb 28, 2021	2,500 mmbtu/d	Cdn$9.19/mmbtu
Natural Gas	AGT	Fixed	Apr 1 – Apr 30, 2021	5,000 mmbtu/d	Cdn$3.88/mmbtu
Natural Gas	AGT differential	Fixed	Dec 2021 – Mar 2022	2,500 mmbtu/d	Cdn$4.16/mmbtu

(1) WCS differential to WTI

Subsequent to December 31, 2020, Headwater entered into the following foreign exchange contract:

Type	Buy Currency	Sell Currency	Rate	Notional Amount	Settlement date
Forward contract	CAD	US	1.2691	US$3 million	March 26, 2021

Non-IFRS Financial Measures

Throughout this MD&A, the Company uses the terms "operating cash flow", "adjusted funds flow from operations", "adjusted working capital" and "free cash flow". These terms do not have any standardized meaning as prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other issuers.

Operating cash flow is calculated as sales plus realized gains or losses on financial derivatives, less royalties, blending and transportation expense and production expense, as follows:

	Three months ended December 31,		Year ended, December 31,	
	2020	2019	2020	2019
	(thousands of dollars)			
Sales	6,626	2,310	9,499	9,333
Realized gain on financial derivatives	1,578	793	5,515	3,691
Royalties	(584)	(52)	(656)	(230)
Blending and transportation	(1,115)	-	(1,115)	-
Production expense	(1,199)	(657)	(2,899)	(2,611)
Operating cash flow	5,306	2,394	10,344	10,183

Adjusted funds flow from operations is used by the Company to analyze operating performance. Adjusted funds flow from operations is defined as cash flows from operating activities before changes in non-cash working capital and transaction costs, as follows:

	Three months ended December 31,		Year ended, December 31,	
	2020	2019	2020	2019
	(thousands of dollars)			
Cash flow provided by (used in) operating activities	(1,451)	(192)	230	8,861
Changes in non–cash working capital	3,319	2,121	1,222	(655)
Transaction costs	2,948	-	7,330	-
Adjusted funds flow from operations	4,816	1,929	8,782	8,206

Adjusted working capital is used by the Company to measure liquidity. Adjusted working capital is defined as working capital excluding the effects of the Company's financial derivative receivable and warrant liability, as follows:

	As at December 31, 2020	As at December 31, 2019
	(thousands of dollars)	
Working capital	70,528	64,622
Financial derivative receivable	(74)	(1,481)
Warrant liability	10,305	-
Adjusted working capital	80,759	63,141

Headwater uses free cash flow as an indicator of liquidity to measure funds available after capital investment. Free cash flow is defined as adjusted funds flow from operations after development capital expenditures, as follows:

	As at December 31, 2020	As at December 31, 2019
	(thousands of dollars)	
Adjusted funds flow from operations	8,782	8,206
Development capital expenditures	(2,277)	(685)
Free cash flow	6,505	7,521

Operating Metrics

Operating metrics including operating netback, adjusted funds flow netback and adjusted funds flow per share are common metrics used in the oil and gas industry and are used by management to better analyze the Company's performance against prior periods on a comparable basis. These metrics have no equivalent IFRS measure and are therefore excluded from the discussion under "Non-IFRS Financial Measures". They also may not be comparable with the calculation of similar measures presented by other issuers.

Operating netback and adjusted funds flow netback are presented as operating cash flow and adjusted funds flow from operations on a per boe basis. Adjusted funds flow per share is calculated as adjusted funds flow from operations divided by the number of weighted average basic or diluted shares outstanding during the period. See the table under the heading "Adjusted Funds Flow from Operations and Net Income" in this MD&A for additional details on how each of these metrics has been calculated.

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, 2020 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, 2020. There have been no changes in the ICFR during the period from October 1, 2020 to December 31, 2020 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 amount 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 pandemic has adversely impacted global commercial activity, including significantly reducing worldwide demand for crude oil and natural gas.

The full extent of the impact of COVID-19 on the Company's operations and future financial performance, including the recoverable amounts of its exploration and evaluation assets and property, plant and equipment, is currently unknown. It will depend on future developments that are uncertain and unpredictable, including the duration and spread of COVID-19, the global roll-out of a vaccine and the virus' continued impact on 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. There is a high degree of uncertainty regarding the estimates and assumptions used in determining the recoverable amounts including future crude oil and natural gas commodity prices, foreign exchange rates, discount rates and the Company's future crude oil and natural gas production. As the understanding of the longer-term impacts of COVID-19 develops, the estimates and assumptions used in determining the recoverable amounts could change and there could be a material financial impact in future periods.

Alternative Sources of Energy

The Company has considered the impacts of climate change and 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 impairment of its oil and gas properties. The measurement of impairment for the Company's oil and gas properties was based on proved plus probable reserves where the majority of the cash flows incorporated into the estimate of the recoverable amount are estimated to be realized in the next ten years. At December 31, 2020, a specific adjustment to the recoverable amount to account for the risk of climate change was not considered necessary, however, the recoverable amount is based on an estimated period of cash flows that indirectly reflects changing energy demands and the discount rate applied in the impairment test incorporates the current cost of capital in the energy industry which indirectly reflects current market trends around climate change. The ultimate period in which global energy markets can transition from carbon-based sources to alternative energy is highly uncertain.

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, 2020 include its New Brunswick CGU consisting of its McCully assets and its Alberta CGU comprised of its Marten Hills 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.

Deferred income taxes

Judgment is required to assess the recognition of deferred income tax assets which is based on the probability that future taxable profits will be sufficient to utilize the underlying taxable amounts. Changes in the estimated future taxable profits, which is based on the cash flows associated with the Company's proved reserves, could materially impact the Company's deferred income tax assets recognized.

b) Key Sources of Estimation Uncertainty

Recoverability of asset carrying value and valuation of reserves

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 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 reserves 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 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.

New Accounting Standard

In October 2018, the IASB issued amendments to the definition of a business in IFRS 3 "Business Combinations". The amendments are intended to assist entities to determine whether a transaction should be accounted for as a business combination or as an asset acquisition. The concentration test is a simplified assessment that results in an asset acquisition if substantially all of the fair value of the gross assets is concentrated in a single identifiable asset or group of similar identifiable assets. If an entity chooses not to apply the concentration test, or the test is failed, then the acquisition is accounted for as a business combination.

The amendments to IFRS 3 are effective for annual reporting periods beginning on or after January 1, 2020 and apply prospectively. The adoption of the amendments to IFRS 3 did not impact the audited annual financial statements.

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.

The Company does not plan to early adopt any amendments issued but not yet effective.

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:

- Public health risks including relating to the COVID-19 pandemic may affect the Company's results, business, financial conditions or liquidity;
- Natural disasters, terrorist acts, civil unrest, pandemics and other disruptions and dislocations may affect the Company's results, business, financial conditions or liquidity;
- Weakness and 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;
- Current and any new regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes, adversely affecting the Company's financial position;
- Various factors may adversely impact the marketability of oil and natural gas, affecting net production revenue, production volumes and development and exploration activities;
- The anticipated benefits of acquisitions may not be achieved and the Company may dispose of non-core assets for less than their carrying value on the financial statements as a result of weak market conditions;
- The Company's business may be adversely affected by recent 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, 2020, dated March 10, 2021, 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.

Finding Development & Acquisition ("FD&A") Costs

This MD&A contains the oil and gas metric FD&A costs, which does not have a standardized meaning or standard method of calculation and therefore such measure may not be comparable to similar measures used by other companies. This metric has been included herein to provide readers with an additional measure to evaluate the Company's performance; however, such measure is not a reliable indicator of the Company’s future performance. FD&A costs is used as a measure of capital efficiency. The FD&A cost calculation includes all capital costs (exploration, development and acquisition capital) for that period plus the change in future development capital for that period. This total capital including the change in the future development capital is then divided by the change in reserves for that period incorporating all revisions and production for that same period. See the Company's press release dated March 10, 2021, which is available on the Company's website at www.headwaterexp.com and under the Company's profile on SEDAR at www.sedar.com, for additional details on the calculation of FD&A costs.

Forward Looking Information

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

- business plans and strategies (including its production optimization and hedging strategies);
- Headwater's intent to maintain an LMR rating above the industry average to minimize its environmental footprint;
- the expectation that Headwater could make use of additional equity or debt financings to fund future acquisitions;
- details of the 2021 approved capital expenditure budget including expected capital expenditures;
- exploration and development plans of Headwater and the expectation Headwater can funds its $100 million capital commitment and contractual obligations through existing working capital and adjusted funds flow from operations;
- revised 2021 guidance including average daily production, fourth quarter 2021 daily production, cash costs, adjusted funds flow from operations, adjusted funds flow netback, exit adjusted working capital and capital expenditures;
- 2021 crude oil and natural gas pricing assumptions; and
- 2021 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, 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, risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration and production; disruptions to the Canadian and global economy resulting from major public health events, including the COVID-19 pandemic, war, terrorist events, political upheavals and other similar events; events impacting the supply and demand for oil and gas including the COVID-19 pandemic and actions taken by the OPEC + group;

delays or changes in plans with respect to exploration or development projects or capital expenditures relating to, among other things, restrictions on activities resulting from the COVID-19 pandemic; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks, commodity price and exchange rate fluctuations; changes in legislation affecting the oil and gas industry and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures), trading of common shares, seasonality, disclosure controls and procedures and internal controls over financial reporting, competition, conflicts of interest, issuance of debt, title to properties, hedging, information systems, litigation, and aboriginal land and rights claims. 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, 2020, dated March 10, 2021, 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.

Reserves Information

Reserves information as at December 31, 2020 as presented herein is based on a report (the “2020 GLJ Reserves Report”) prepared by GLJ Ltd. (“GLJ”) assessing the Company’s reserves effective December 31, 2020 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, 2020 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, 2020, dated March 10, 2021, which is available on the Company's website at and under the Company's profile on SEDAR at www.sedar.com.

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.

SARAH WALTERS (2)
Senior Vice-President, Corporate Services 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.