Hammerhead Resources Inc.

Management's Discussion and Analysis
As at and for the Three Months and Year Ended
December 31, 2022

Dated: March 28, 2023

Management Discussion and Analysis

In this management's discussion and analysis ("MD&A"), unless otherwise indicated or the context otherwise requires, the terms "we", "us", "our", "HHR", "Hammerhead" and "the Company" refers to Hammerhead Resources Inc., as the parent corporation. Hammerhead Resources Inc. was incorporated pursuant to the provisions of the Business Corporations Act (Alberta). On March 11, 2019, the Company incorporated a wholly owned subsidiary, "Prairie Lights Power GP Inc.", and formed an associated limited partnership; "Prairie Lights Power Limited Partnership", in order to initiate a power related project. The project has no active operations as at the date of the MD&A.

The Company is controlled by Riverstone Holdings LLC and its affiliates ("Riverstone"). The Company's head office is located at Eighth Avenue Place, East Tower, Suite 2700, 525-8th Avenue SW, Calgary, Alberta, T2P 1G1.

On February 23, 2023, the Company completed a plan of arrangement pursuant to a business combination agreement with Decarbonization Plus Acquisition Corporation IV ("DCRD"), an affiliate of the Company's controlling shareholder, Riverstone, and certain other parties and their respective shareholders. Pursuant to the plan of arrangement, DCRD amalgamated with a wholly owned subsidiary of the Company which was incorporated for the purpose of effecting the business combination to form Hammerhead Energy Inc. ("HEI"). Also pursuant to the plan of arrangement, Hammerhead Resources Inc. amalgamated with a wholly owned subsidiary of DCRD incorporated to effect the business combination to form Hammerhead Resources ULC, a wholly owned subsidiary of HEI. See the subsection "Business Combination" in this M&DA for further information.

Hammerhead is an oil and natural gas exploration, development and production company. Hammerhead's reserves, producing properties and exploration prospects are located primarily in the province of Alberta in the Deep Basin of West Central Alberta where it is developing multi-zone, liquids-rich oil and gas plays. The consolidated financial statements of the Company, as well as other information relating to the Company can be found on SEDAR at www.sedar.com and EDGAR at www.sec.gov/edgar under the profile for Hammerhead Energy Inc.

The following MD&A provides management's analysis of the Company's results of operations and financial position as at and for the three months and years ended December 31, 2022 and December 31, 2021. This MD&A is dated March 28, 2023 and should be read in conjunction with the audited consolidated financial statements as at and for the years ended December 31, 2022, December 31, 2021 and December 31, 2020 (the "2022 Financial Statements").

This MD&A contains forward-looking statements and non-GAAP measures. Readers are cautioned that the MD&A should be read in conjunction with the Company's disclosures under the headings "Forward-Looking Statements" and "Other Advisories - Non-GAAP Measures" included at the end of this MD&A. Refer to the "Non-GAAP and Other Specified Financial Measures" section of this MD&A for reconciliations and information regarding the following measures and ratios used in this MD&A: "capital expenditures", "available funding", "operating netback", "funds from operations", "adjusted funds from operations", "free funds flow", operating netback per boe", "funds from operations per boe", "funds from operations per basic share and diluted share", "adjusted funds from operations", "adjusted funds from operations per basic and diluted share", "adjusted EBITDA", "annualized quarterly adjusted EBITDA", "adjusted working capital", "net debt", "net debt to adjusted EBITDA" and "net debt to annualized quarterly adjusted EBITDA".

All financial information has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") as set out in Part I of the *CPA Canada Handbook – Accounting*, using accounting policies consistent with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

Unless otherwise noted, all financial information provided herein is reported in Canadian dollars and tabular dollar amounts are presented in thousands. Production volumes are presented on a working-interest basis before royalties.

Operational and Financial Summary

(Cdn$ thousands, except per share amounts, production and unit prices)	Three Months Ended December 31, 2022	2021	% Change	Year Ended December 31, 2022	2021	% Change
Production volumes						
Crude oil (bbls/d)	8,958	7,135	26	9,531	6,816	40
Natural gas (Mcf/d)	99,512	101,028	(2)	110,273	102,516	8
Natural gas liquids (bbls/d)	3,984	3,787	5	4,171	3,903	7
Total (boe/d)	29,527	27,760	6	32,081	27,805	15
Liquids weighting %	44	39		43	39	
Oil and gas revenue ($/boe)	73.14	54.50	34	72.13	43.34	66
Operating netback ($/boe) [1]	43.96	20.22	117	39.10	15.90	146
Oil and gas revenue	198,676	139,183	43	844,644	439,843	92
Operating netback [2]	119,414	51,653	131	457,884	161,274	184
Net cash from operating activities	76,131	33,540	127	371,355	121,111	207
Per common share – basic	0.19	0.09	111	0.95	0.31	206
Per common share – diluted	0.07	0.04	75	0.39	0.31	26
Adjusted funds from operations [3]	108,937	43,528	150	423,533	133,130	218
Per common share – basic [4]	0.28	0.11	155	1.08	0.34	218
Per common share – diluted [4]	0.10	0.05	100	0.44	0.34	29
Net profit (loss)	67,298	37,139	81	225,100	(71,821)	N/A
Net profit (loss) attributable to ordinary equity holders	60,584	31,344	93	199,865	(93,601)	N/A
Per common share – basic	0.15	0.08	88	0.51	(0.24)	N/A
Per common share – diluted	0.06	0.03	100	0.21	(0.24)	N/A
Net cash used in investing activities	145,556	42,190	245	368,153	91,180	304
Capital expenditures [5]	173,669	68,385	154	383,876	138,544	177
Free funds flow [6]	(64,732)	(24,857)	160	39,534	(5,414)	N/A
Weighted average common shares outstanding [7]						
Basic	392,556	391,117	—	391,803	391,106	—
Diluted	1,058,515	952,281	11	961,751	391,106	146

FINANCIAL	As at December 31, 2022	2021	% Change
Adjusted working capital deficit [8]	32,915	52,443	(37)
Available funding [9]	309,985	188,957	64
Net debt [10]	291,647	293,490	(1)

1 Operating netback per boe is a non-GAAP measure. Oil and gas revenue per boe is the most directly comparable GAAP measure to operating netback per boe. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

2 Operating netback is a non-GAAP measure. Oil and gas revenue is the most directly comparable GAAP measure to operating netback. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

3 Adjusted funds from operations is a non-GAAP measure. Net cash from operating activities is the most directly comparable GAAP measure to adjusted funds from operations. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

4 Adjusted funds from operations per basic and diluted common share are non-GAAP measures. Net cash from operating activities per basic and diluted share are the most directly comparable GAAP measure to adjusted funds from operations per basic and diluted common share. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

5 Capital expenditures is a non-GAAP measure. Net cash used in investing activities is the most directly comparable GAAP measure to capital expenditures. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

6 Free funds flow is a non-GAAP measures. Net cash from operating activities is the most directly comparable GAAP measure to free funds flow. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

7 Following the transaction referred to in subsection "Business Combination" in this MD&A, the combined entity has 90,927,765 common shares, 28,549,991 warrants, 5,187,659 RSUs, and 664,328 options issued and outstanding as of the date of this report, March 28, 2023.

8 Adjusted working capital deficit is a capital management measure. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

9 Available funding is a non-GAAP measure. Working capital deficit is the most directly comparable GAAP measure to available funding. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

10 Net debt is a non-GAAP measure. The Company's third party debt obligations of the bank debt and the term debt are the most directly comparable GAAP measures for net debt. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

Operational and Financial Summary of Selected Annual Information

	Year Ended December 31,		
(Cdn$ thousands, except per share amounts, production and unit prices)	**2022**	2021	2020
Production volumes			
Crude oil (bbls/d)	**9,531**	6,816	7,798
Natural gas (Mcf/d)	**110,273**	102,516	111,450
Natural gas liquids (bbls/d)	**4,171**	3,903	3,658
Total (boe/d)	**32,081**	27,805	30,031
Liquids weighting %	**43**	39	38
Oil and gas revenue ($/boe)	**72.13**	43.34	23.97
Oil and gas revenue	**844,644**	439,843	263,514
Net cash from operating activities	**371,355**	121,111	119,686
Per common share – basic	**0.95**	0.31	0.31
Per common share – diluted	**0.39**	0.31	0.16
Net profit (loss)	**225,100**	(71,821)	53,410
Net profit (loss) attributable to ordinary equity holders - Diluted	**199,865**	(93,601)	34,669
Per common share – basic	**0.51**	(0.24)	0.09
Per common share – diluted	**0.21**	(0.24)	0.05
Net cash used in investing activities	**368,153**	91,180	113,328
Weighted average common shares outstanding [1]			
Basic	**391,803**	391,106	391,052
Diluted	**961,751**	391,106	728,575

1 Following the transaction referred to in subsection "Business Combination" in this MD&A, the combined entity has 90,927,765 common shares, 28,549,991 warrants, 5,187,659 RSUs, and 664,328 options issued and outstanding as of the date of this report, March 28, 2023.

Fourth Quarter 2022 Operating and Financial Highlights:

- Production averaged 29,527 boe/d in the fourth quarter of 2022, a 1,767 boe/d increase from the same period of 2021. New production from 34 gross (34 net) wells brought on-stream since December 31, 2021 offset production declines on existing wells.

- The Company's liquids weighting was 44% during the fourth quarter of 2022, compared to 39% in the same period of 2021. The increase was driven by high oil production from multiple pads brought on-stream throughout 2022.

- Oil and gas revenue for the three months ended December 31, 2022 and 2021 was $198.7 million and $139.2 million, respectively. Oil and gas revenue is the most directly comparable GAAP measure for operating netback, which is a non-GAAP measure. Operating netback was $119.4 million or $43.96/boe for the fourth quarter of 2022, reflecting an increase of $67.8 million or $23.74/boe from the same period of 2021. The increase was driven by improvements in commodity pricing which generated $18.64/boe of additional revenue and a $9.61/boe decrease in realized losses on risk management contracts. This was partially offset by a $2.73/boe increase in royalty expense.

- Net cash from operating activities for the three months ended December 31, 2022 and 2021 was $76.1 million and $33.5 million, respectively. Net cash from operating activities is the most directly comparable GAAP measure for funds from operations, which is a non-GAAP measure. Funds from operations was $106.1 million during the fourth quarter of 2022, a $75.8 million or 250% increase from the same quarter of 2021. The increase is primarily due to a $67.8 million increase in operating netback and a $13.7 million decrease in optimization fees, partially offset by a $3.5 million increase in cash interest expense.

- The Company reported a net profit of $67.3 million for the three months ended December 31, 2022, compared to $37.1 million in the same period of 2021. The $30.2 million improvement was primarily due to a $75.8 million increase in funds from operations, partially offset by a $31.7 million increase in deferred income tax expense and a $12.6 million decrease in unrealized gain on risk management contracts.

- Net cash used in investing activities for the three months ended December 31, 2022 and 2021 was $145.6 million and $42.2 million, respectively. Net cash used in investing activities is the most directly comparable GAAP measure for capital expenditures, which is a non-GAAP measure. Capital expenditures during the fourth quarter of 2022 were $173.7 million, with the Company focusing its investments on well development activities in both the Karr and Gold Creek areas, along with spending on non-well activities in the Karr area. In Karr, the Company completed and tied in a nine gross (nine net) well pad and drilled and tied in a portion of 10 gross (8.05 net) wells across two pads. The remaining funds in Karr were used in various non-well infrastructure projects. In Gold Creek, the Company drilled, completed and tied in a three gross (three net) well pad.

- In December 2022, Hammerhead assets were certified under the EO100™ Standard for Responsible Energy Development, covering more than 100,000 net acres in the Montney formation. The EO100™ Standard encompasses the following five principles with a commitment for continuous improvement to each: Corporate Governance, Transparency & Ethics; Human Rights, Social Impact & Community Development; Indigenous People's Rights; Fair Labor & Working Conditions; and Climate Change, Biodiversity & Environment.

Year-to-Date 2022 Operating and Financial Highlights:

- Production averaged 32,081 boe/d for the years ended December 31, 2022, a 4,276 boe/d increase from the same period of 2021. New production from 34 gross (34 net) wells brought on-stream since December 31, 2021 offset production declines on existing wells.

- The Company's liquids weighting was 43% during the years ended December 31, 2022, compared to 39% in the same period of 2021. The increase was driven by higher oil production from multiple pads brought on-stream throughout 2022.

- Oil and gas revenue for the years ended December 31, 2022 and 2021 was $844.6 million and $439.8 million, respectively. Oil and gas revenue is the most directly comparable GAAP measure for operating netback, which is a non-GAAP measure. Operating netback was $457.9 million or $39.10/boe for the year ended December 31, 2022, reflecting an increase of $296.6 million or $23.20/boe from the same period of 2021. Improvements in commodity pricing generated $28.79/boe of additional revenue, which was partially offset by a $5.13/boe increase in royalty expense.

- Net cash from operating activities for the years ended December 31, 2022 and 2021 was $371.4 million and $121.1 million, respectively. Net cash from operating activities is the most directly comparable GAAP measure for funds from operations, which is a non-GAAP measure. Funds from operations was $405.0 million during the year ended December 31, 2022, a $290.5 million or 254% increase from the same period of 2021. The increase is primarily due to a $296.6 million increase in operating netback, and a $19.7 million decrease in optimization fees. This was partially offset by a $19.1 million increase in transaction costs, a $5.5 million increase in cash interest expense, and a $2.4 million increase in realized foreign exchange loss.

- The Company reported a net profit of $225.1 million for the year ended December 31, 2022, compared to a net loss of $71.8 million in the same period of 2021. The $296.9 million improvement was primarily due to a $290.5 million increase in funds from operations and a $54.8 million increase in unrealized gain on risk management contracts. This was partially offset by a $31.7 million increase in deferred income tax expense and all remaining non-cash impacts decreasing net profit by $16.6 million.

- Net cash used in investing activities for the year ended December 31, 2022 and 2021 was $368.2 million and $91.2 million, respectively. Net cash used in investing activities is the most directly comparable GAAP measure for capital expenditures, which is a non-GAAP measure. Capital expenditures during the year ended December 31, 2022 were $383.9 million, with the Company focusing its investments on well development activities in both the Karr and Gold Creek areas, along with spending on non-well activities in the Karr area. In Karr, the Company drilled, completed and tied-in two pads with a combined 13 gross (13 net) wells. Additionally, the Company drilled and tied-in a portion of 10 gross (8.05 net) wells across two pads and incurred spend on battery, facility and pipeline expansion projects. In Gold Creek, the Company drilled, completed and tied-in three pads with a combined 12 gross (12 net) wells.

- Effective September 26, 2022, the Company repaid, at par value, US$59.3 million of principal and accrued interest on its term debt, reducing the aggregate principal balance outstanding down to US$56.5 million.

- For the year ended December 31, 2022 the Company incurred $19.1 million in transaction costs related to the pending business combination with DCRD.

- Effective February 23, 2023, the Company completed a business combination agreement with DCRD.

Business Combination

On February 23, 2023, the Company completed a plan of arrangement pursuant to a business combination agreement with DCRD, an affiliate of the Company's controlling shareholder, Riverstone, and certain other parties and their respective shareholders. Pursuant to the plan of arrangement, DCRD amalgamated with a wholly owned subsidiary of the Company which was incorporated for the purpose of effecting the business combination to form HEI. Also pursuant to the plan of arrangement, Hammerhead Resources Inc. amalgamated with a wholly owned subsidiary of DCRD incorporated to effect the business combination to form Hammerhead Resources ULC, a wholly owned subsidiary of HEI. The transaction is considered a business combination under common control, and is accounted for under IFRS 2 Share Based Payment as it does not meet the definition of a business combination under IFRS 3 Business Combinations.

HEI's common shares and warrants are publicly traded on the Nasdaq Stock Market LLC (“Nasdaq”) under the symbols “HHRS” and “HHRSW”, respectively and the Toronto Stock Exchange (“TSX”) under the symbols “HHRS” and “HHRS.WT,” respectively.

As a result of the combination, the Company's common shares, preferred shares, and 2020 warrants have been exercised if applicable, and converted to Class A common shares of HEI. The 2013 warrants were settled for a cash payment of $0.028 per warrant. The limited recourse loans of $5.8 million were terminated. HEI issued a combined total of 90,778,275 common shares and 28,549,991 warrants to the shareholders of Hammerhead and DCRD.

Transaction costs incurred directly by the Company for the year ended December 31, 2022 in connection with the transaction were $19.1 million.

Results of Operations

Production

	Three Months Ended December 31,			Year Ended December 31,			
	2022	2021	% Change	**2022**	2021	% Change	2020
Crude oil and field condensate (bbls/d)	**8,958**	7,135	26	**9,531**	6,816	40	7,798
Natural gas (Mcf/d)	**99,512**	101,028	(2)	**110,273**	102,516	8	111,450
Natural gas liquids (bbls/d)	**3,984**	3,787	5	**4,171**	3,903	7	3,658
Total (boe/d)	**29,527**	27,760	6	**32,081**	27,805	15	30,031
Liquids weighting %	**44**	39		**43**	39		38

Average production during the three months ended December 31, 2022, was 29,527 boe/d, up 6% from the fourth quarter of 2021. During the year ended December 31, 2022, average production was 32,081 boe/d, up 15% from the same period of 2021. The growth in production reflects 34 gross (34 net) wells brought on-stream since December 31, 2021, which offset production declines on existing wells.

The Company's liquids weighting was 44% and 43%, respectively, for the three months and year ended December 31, 2022, compared to 39% for both periods in 2021. The increase in liquids weighting was driven by higher oil production from multiple pads brought on-stream throughout 2022 in the Karr area.

Realized Prices and Benchmark Prices

	Three Months Ended December 31,			Year Ended December 31,			
(Per unit amounts)	**2022**	2021	% Change	**2022**	2021	% Change	2020
Average Realized Prices							
Crude oil and field condensate ($/bbl)	**108.69**	92.34	18	**120.10**	80.03	50	44.04
Natural gas ($/Mcf) [1]	**9.21**	5.88	57	**7.84**	4.44	77	2.56
Natural gas liquids ($/bbl)	**67.62**	68.60	(1)	**73.19**	52.51	39	25.04
Total ($/boe)	**73.14**	54.50	34	**72.13**	43.34	66	23.97
Benchmark Prices							
Crude oil							
WTI (Cdn$/bbl)	**112.23**	97.18	15	**122.42**	85.14	44	52.53
Edmonton Light Sweet (Cdn$/bbl)	**109.98**	93.26	18	**120.08**	80.28	50	45.33
WTI/Edmonton Light Sweet (Cdn$/bbl)	**(2.25)**	(3.92)	(43)	**(2.34)**	(4.87)	(52)	(7.20)
Natural gas							
AECO 5A (Cdn$/GJ)	**4.84**	4.41	10	**5.03**	3.43	47	2.11
AECO 5A (Cdn$/Mcf) [2]	**5.15**	4.70	10	**5.36**	3.66	46	2.25
NYMEX (US$/MMBtu)	**6.27**	5.83	8	**6.64**	3.85	72	2.08
NYMEX (Cdn$/Mcf) [2]	**8.60**	7.41	16	**8.74**	4.87	79	2.80
Union-Dawn (US$/MMBtu)	**5.16**	4.65	11	**6.05**	3.61	68	1.87
Union-Dawn (Cdn$/Mcf) [2]	**7.07**	5.90	20	**7.94**	4.57	74	2.52
Chicago City-Gate (US$/MMBtu)	**5.38**	4.58	17	**6.10**	5.06	21	1.88
Chicago City-Gate (Cdn$/Mcf) [2]	**7.37**	5.82	27	**8.01**	6.43	25	2.54
Stanfield (US$/MMBtu)	**14.45**	5.32	172	**8.32**	3.87	115	2.03
Stanfield (Cdn$/Mcf) [2]	**19.80**	6.77	192	**11.06**	4.90	126	2.73
Malin (US$/MMBtu)	**14.42**	5.36	169	**8.42**	3.94	114	2.06
Malin (Cdn$/Mcf) [2]	**19.76**	6.82	190	**11.20**	4.99	124	2.77
Average foreign exchange							
Exchange rate - US$/Cdn$	**1.36**	1.26	8	**1.30**	1.25	4	1.34

1 At the Company's current heating value of 42.0 GJ/e^3m^3, 1 mcf of natural gas is approximately 1.18 GJ.
2 At industry average heating values of 37.8 GJ/e^3m^3, 1 mcf of natural gas is approximately 1.065 GJ.

Crude oil and field condensate

The majority of the Company's crude oil and field condensate production is delivered and sold in Central Alberta through firm service commitments on Pembina's pipeline systems. The price that Hammerhead receives for crude oil and field condensate production is primarily driven by global supply and demand and the Edmonton light sweet oil and condensate price differentials.

During the three months and year ended December 31, 2022, the Company's realized crude oil and field condensate price increased by $16.35/bbl or 18% and $40.07/bbl or 50%, respectively, compared to the same periods in 2021. Improved pricing was driven by a rise in demand for oil products coupled with diminished supply from low levels of inventory experienced worldwide and sanctions on Russian oil exports issued in response to the Russia-Ukraine war. Though prices have improved over the 2021 period, volatility persists from the global concern over a potential economic recession and China's impact on demand.

Natural Gas

The Company's natural gas transportation capacity provides geographical diversification across North America. The Company has firm service commitments to deliver and sell its natural gas production to the Alberta, Eastern Canada and United States (Midwest and West Path) markets.

	Three Months Ended December 31,		Year Ended December 31,		
% weighting of total gas sales	**2022**	2021	**2022**	2021	2020
Alberta	**41**	40	**47**	41	52
Eastern Canada	**32**	33	**29**	32	29
United States	**27**	27	**24**	27	19

For the three months and year ended December 31, 2022, Hammerhead's realized natural gas price increased by $3.33/mcf or 57%, and $3.40/mcf or 77%, respectively, compared to the same periods in 2021. The increase in the Company's realized price was driven by improvements in benchmark prices across all North American markets, and significant improvements in the West Path United States benchmark pricing.

During the three months and year ended December 31, 2022, North American prices increased due to high demand from liquified natural gas ("LNG") facilities as European markets experienced supply uncertainty due to the Russia-Ukraine war. Prices in Alberta were impacted by third party pipeline maintenance which kept AECO prices comparatively lower than other North American markets. Increases at the West Path sales points in the United States were driven by regional weather and demand.

NGL

The Company's natural gas liquids and plant condensate is currently sold on the Alberta market, but achieves geographical diversification in pricing through Pembina Pipeline's marketing pool. Pembina operates a pool of sales that provides access to the United States, Asia and Eastern Canadian markets, with market weightings adjusted for supply and demand outlook and seasonality.

For the three months and year ended December 31, 2022, Hammerhead's realized NGL price decreased by $0.98/bbl or 1%, and increased by $20.68/bbl or 39%, respectively, compared to the same periods in 2021. Warmer weather and inventory recoveries in the US during the fourth quarter of 2022 tempered previous price improvements. Higher demand for North American NGL products and diminished supply from low inventory levels compounded by continued political unrest from the Russia-Ukraine war, drove improvements in pricing for the year ended December 31, 2022.

Revenue

	Three Months Ended December 31,			Year Ended December 31,			
(Cdn$ thousands, except per boe)	**2022**	2021	% Change	**2022**	2021	% Change	2020
Crude oil and field condensate	**89,579**	60,615	48	**417,791**	199,108	110	125,711
Natural gas	**84,317**	54,663	54	**315,423**	165,957	90	104,267
Natural gas liquids	**24,780**	23,905	4	**111,430**	74,778	49	33,356
Oil and gas revenue	**198,676**	139,183	43	**844,644**	439,843	92	263,514
Revenue - $/boe	**73.14**	54.50	34	**72.13**	43.34	66	23.97

For the three months and year ended December 31, 2022, the Company earned revenue of $198.7 million and $844.6 million, respectively, compared to $139.2 million and $439.8 million in the comparative periods of 2021. The increase in both periods is primarily due to higher realized prices across all commodities with increased production further contributing to the rise in revenue for the year.

Royalty Expense

	Three Months Ended December 31,			Year Ended December 31,			
(Cdn$ thousands, except per boe)	**2022**	2021	% Change	**2022**	2021	% Change	2020
Royalty expense	**22,855**	14,511	58	**104,508**	38,577	171	17,185
Royalty expense - $/boe	**8.41**	5.68	48	**8.93**	3.80	135	1.56
Percentage of revenue	**12**	10		**12**	9		7

Hammerhead pays royalties to the Province of Alberta in respect of the Company's production and sales volumes in accordance with the established royalty regime. The majority of the Company's royalties are paid to the Crown, which are based on various sliding scales that are dependent on incentives, production volumes and commodity prices. Hammerhead's wells spud on or after January 1, 2017 qualify for the Crown's Modernized Royalty Framework ("MRF") incentive program which has a low initial 5% royalty rate until a threshold return of capital has been achieved. As of the latter half of 2018 and up until April 2022, the Company qualified for the Crown's Enhanced Hydrocarbon Recovery Program ("EHRP") associated with a pilot waterflood program in a portion of the Company's Gold Creek area. The EHRP provided for a flat royalty of 5% on all commodities produced from specific wells impacted by the waterflood program during this time period.

The Company receives a monthly Gas Cost Allowance ("GCA") credit from the Province of Alberta for expenses incurred to process and transport the Crown's portion of natural gas production. The credit is applied to the royalties that would have been owed to the Crown. The GCA credit is assessed annually every June and is subject to a true-up adjustment as a payable to the Crown or a receivable in the form of a credit to the Company.

During the fourth quarter of 2022, royalty expenses increased $8.3 million or $2.73/boe compared to the fourth quarter of 2021. On a percentage of revenue basis, royalties increased by 2% over the same period. During the year ended December 31, 2022, royalty expenses increased $65.9 million or $5.13/boe, compared to the same period of 2021. On a percentage of revenue basis, royalties increased by 3% over the same period.

Higher commodity prices, with the added impact of fewer wells receiving an incentivized rate, drove the increase in royalties for the three months and year ended December 31, 2022 when compared to the same periods of 2021. With improved pricing, and high production levels, MRF incentive wells achieve their threshold return of capital sooner, resulting in a shorter time period for new wells to capture the incentivized rate, and therefore compounding the increase to royalty expense.

Operating Expense

	Three Months Ended December 31,			Year Ended December 31,			
(Cdn$ thousands, except per boe)	**2022**	2021	% Change	**2022**	2021	% Change	2020
Gas gathering and processing	**11,582**	8,194	41	**42,762**	37,900	13	37,532
Chemicals and fuel	**4,423**	3,933	12	**18,755**	11,819	59	11,114
Repairs and maintenance	**2,982**	2,499	19	**15,025**	10,187	47	8,448
Staff and contractor costs	**2,540**	2,184	16	**9,855**	8,200	20	9,852
Well servicing	**733**	610	20	**2,744**	1,916	43	1,206
Other	**4,543**	3,982	14	**17,451**	12,699	37	9,325
Operating expense	**26,803**	21,402	25	**106,592**	82,721	29	77,477
Operating expense - $/boe	**9.87**	8.38	18	**9.10**	8.15	12	7.05

For the three months ended December 31, 2022, operating expense increased $5.4 million or $1.49/boe, compared to the corresponding period of 2021. The increase was driven by higher gas gathering and processing costs, as well as increased production volumes. The rise in gas gathering and processing fees was caused by a favorable equalization adjustment that lowered these fees in the fourth quarter of 2021, an unfavorable equalization adjustment that increased these fees in the fourth quarter of 2022, and higher levels of firm service commitments in 2022.

For the year ended December 31, 2022, operating expense increased $23.9 million or $0.95/boe, compared to the corresponding period of 2021. The increase is due to additional production volumes, as well as higher per boe costs for chemicals and fuel, repairs and maintenance and other operating costs. Higher per unit pricing and consumption required by increased production drove the increased chemicals and fuel expense. The increase in repairs and maintenance charges reflects three battery turnarounds performed in the second quarter of 2022, compared to one corresponding turnaround in 2021. For other operating costs, the increase is due to additional water disposal costs for new wells on stream and higher carbon tax expense resulting from a change in rates under the Government TIER program.

Transportation Expense

	Three Months Ended December 31,			Year Ended December 31,			
(Cdn$ thousands)	**2022**	2021	% Change	**2022**	2021	% Change	2020
Transportation expense - gross	**17,202**	15,421	12	**69,683**	62,044	12	57,393
Transportation income	**—**	(12)	(100)	**—**	(180)	(100)	(411)
Net transportation expense	**17,202**	15,409	12	**69,683**	61,864	13	56,982

(Cdn$ per boe)							
Transportation expense - gross	**6.33**	6.04	5	**5.95**	6.11	(3)	5.22
Transportation income	**—**	—	—	**—**	(0.02)	(100)	(0.04)
Net transportation expense	**6.33**	6.04	5	**5.95**	6.09	(2)	5.18

During the three months ended December 31, 2022, gross transportation expense was $17.2 million or $6.33/boe, compared to $15.4 million or $6.04/boe in the same period of 2021. During the year ended December 31, 2022, gross transportation expense was $69.7 million or $5.95/boe, compared to $62.0 million or $6.11/boe in the same period of 2021.

The increase in gross transportation expense for the three months and year ended December 31, 2022 of $1.8 million and $7.6 million, respectively, was due to higher overall volumes. The $0.29/boe increase for the three months ended December 31, 2022 was due to an unfavorable third-party adjustment that raised NGL transportation costs in the fourth quarter of 2022. Conversely, the decrease in per unit fees of $0.14/boe for the year ended December 31, 2022 was caused by lower take-or-pay charges throughout the year as increased oil production allowed the Company to fulfill its oil firm service commitments.

Risk Management Contracts

The Company's risk management program is primarily designed to reduce volatility in revenue and cash flow, help ensure sufficient cash flow to service debt obligations and provide consistency for the Company's capital program.

Risk management contract settlements are recognized as a realized gain or loss. The fair value of the Company's unsettled risk management contracts is recorded as an asset or liability at each reporting period with any change in the mark-to-market positions of the outstanding contracts recognized as an unrealized gain or loss in net profit (loss). Both realized and unrealized gains and losses on risk management contracts vary based on fluctuations related to the specific terms of outstanding contracts in the period including contract types, contract quantities, contract prices and the underlying commodity reference prices.

The following table summarizes the liability or asset position of risk management contracts outstanding:

(Cdn$ thousands)	**December 31, 2022**	December 31, 2021
Crude liability	**(5,801)**	(13,463)
Gas asset (liability)	**17,808**	(2,773)
NGL liability	**—**	(9,869)
Net fair value asset (liability)	**12,007**	(26,105)

The following table summarizes the realized losses on risk management contract settlements, as well as the unrealized losses or gains related to changes in the fair value of outstanding contracts:

	Three Months Ended December 31,			Year Ended December 31,			
(Cdn$ thousands)	2022	2021	% Change	2022	2021	% Change	2020
Realized loss on risk management contracts [1]	(12,402)	(36,208)	(66)	(105,977)	(95,407)	11	66,121
Unrealized gain (loss) on risk management contracts [2]	33,657	46,238	(27)	38,112	(16,649)	N/A	(18,353)
Total gain (loss) on risk management contracts	21,255	10,030	112	(67,865)	(112,056)	(39)	47,768

(Cdn$ per boe)							
Realized loss on risk management contracts [1]	(4.57)	(14.18)	(68)	(9.05)	(9.40)	(4)	6.02
Unrealized gain (loss) on risk management contracts [2]	12.39	18.10	(32)	3.25	(1.64)	N/A	(1.67)
Total gain (loss) on risk management contracts	7.82	3.92	99	(5.80)	(11.04)	(47)	4.35

1 Represents actual cash settlements under the respective contracts.
2 Represents the change in fair value of contracts outstanding during the period.

During the three months ended December 31, 2022, the Company incurred a realized loss on risk management contracts of $12.4 million, compared to a realized loss of $36.2 million in the comparative period of 2021. The decreased loss primarily relates to a lower volume of oil contracts and a lower spread between hedged prices and realized prices.

During the year ended December 31, 2022, the Company incurred a realized loss on risk management contracts of $106.0 million, compared to a realized loss of $95.4 million in the comparative period of 2021. The increased loss relates primarily to improvements in Dawn natural gas and WTI oil realized prices relative to hedged prices.

The unrealized gain on risk management contracts of $33.7 million for the three months ended December 31, 2022 is primarily due to the deterioration of gas forward pricing from September 30 to December 31, relative to the hedged prices of the risk management contracts outstanding and the realized settlement of out of the money contracts during the quarter. The prior year unrealized gain on risk management contracts of $46.2 million for the three months ended December 31, 2021 was primarily due to the realized settlement of out of the money contracts during the quarter, as well as the deterioration of Dawn forward pricing over the quarter.

The unrealized gain on risk management contracts of $38.1 million for the year ended December 31, 2022 is primarily due to the settlement of out of the money contracts throughout the year on all commodities and the deterioration of natural gas forward pricing from December 31, 2021 to December 31, 2022, relative to the hedged prices of the risk management contracts outstanding. The unrealized loss on risk management contracts of $16.6 million for the year ended December 31, 2021 was due to improvements in strip pricing across all commodities from December 31, 2020 to December 31, 2021, relative to the hedged prices of the risk management contracts outstanding.

As at December 31, 2022, the Company held the following outstanding risk management contracts:

Remaining Term	**Reference**	**Total Daily Volume** *(bbls/d)*	**Weighted Average** *(Price/bbls)*
Crude Oil Swaps			
Jan 1, 2023 – Jun 30, 2023	US$ WTI	1,000	87.00
Jan 1, 2023 – Dec 31, 2023	US$ WTI	1,100	65.00

Remaining Term	Reference	Total Daily Volume (GJ/d)	Total Daily Volume (MMbtu/d)	Weighted Average (CDN$/GJ)	Weighted Average (US$/MMbtu)
Natural Gas Swaps					
Apr 1, 2023 - Sep 30, 2023	CDN$ AECO	30,000	—	4.96	—
Jan 1, 2023 - Jun 30, 2023	US$ Dawn	—	30,000	—	3.04
Jan 1, 2023 - Dec 31, 2023	US$ AECO - NYMEX	—	30,000	—	(1.48)
Natural Gas Collar					
Jan 1, 2023 - Dec 31, 2023	US$ NYMEX	—	30,000	—	5.00 - 9.80

Operating Netback

	Three Months Ended December 31,			Year Ended December 31,			
(Cdn$ thousands)	**2022**	2021	% Change	**2022**	2021	% Change	2020
Revenue	**198,676**	139,183	43	**844,644**	439,843	92	263,514
Royalties	**(22,855)**	(14,511)	58	**(104,508)**	(38,577)	171	(17,185)
Operating expense	**(26,803)**	(21,402)	25	**(106,592)**	(82,721)	29	(77,477)
Net transportation expense	**(17,202)**	(15,409)	12	**(69,683)**	(61,864)	13	(56,982)
Operating netback, excluding realized losses on risk management contracts	**131,816**	87,861	50	**563,861**	256,681	120	111,870
Realized losses on risk management contracts	**(12,402)**	(36,208)	(66)	**(105,977)**	(95,407)	11	66,121
Operating netback [1]	**119,414**	51,653	131	**457,884**	161,274	184	177,991

(Cdn$ per boe)							
Revenue	**73.14**	54.50	34	**72.13**	43.34	66	23.97
Royalties	**(8.41)**	(5.68)	48	**(8.93)**	(3.80)	135	(1.56)
Operating expense	**(9.87)**	(8.38)	18	**(9.10)**	(8.15)	12	(7.05)
Net transportation expense	**(6.33)**	(6.04)	5	**(5.95)**	(6.09)	(2)	(5.18)
Operating netback, excluding realized losses on risk management contracts	**48.53**	34.40	41	**48.15**	25.30	90	10.18
Realized losses on risk management contracts	**(4.57)**	(14.18)	(68)	**(9.05)**	(9.40)	(4)	6.02
Operating netback per boe [2]	**43.96**	20.22	117	**39.10**	15.90	146	16.20

1 Operating netback is a non-GAAP measure. Oil and gas revenue is the most directly comparable GAAP measure to operating netback. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

2 Operating netback per boe is a non-GAAP measure. Oil and gas revenue per boe is the most directly comparable GAAP measure to operating netback per boe. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

For the three months ended December 31, 2022, the Company's operating netback was $43.96/boe, an increase of $23.74/boe from the corresponding period of 2021. The increase was driven by improvements in commodity pricing which generated $18.64/boe of additional revenue and a $9.61/boe decrease in realized losses on risk management contracts. Royalties also increased alongside revenue, resulting in a $2.73/boe increase in royalty expense.

For the year ended December 31, 2022, the Company's operating netback was $39.10/boe, an increase of $23.20/boe from the prior year. Improvements in commodity pricing generated $28.79/boe of additional revenue, which was partially offset by a corresponding $5.13/boe increase in royalty expense.

General and Administrative ("G&A") Expense

	Three Months Ended December 31,			Year Ended December 31,			
(Cdn$ thousands, except per boe)	2022	2021	% Change	2022	2021	% Change	2020
Salaries and benefits	4,306	5,663	(24)	18,573	19,370	(4)	16,525
Information technology	659	574	15	2,423	2,195	10	1,958
Insurance	505	338	49	1,870	1,059	77	844
Professional fees [1]	503	469	7	1,595	1,467	9	3,038
Office rent	189	200	(6)	692	751	(8)	736
Other	730	548	33	2,243	1,418	58	1,027
Gross G&A expense	6,892	7,792	(12)	27,396	26,260	4	24,128
Capitalized G&A expense	(1,349)	(1,151)	17	(5,128)	(4,695)	9	(2,290)
Net G&A expense	5,543	6,641	(17)	22,268	21,565	3	21,838
Net G&A - $/boe	2.04	2.60	(22)	1.90	2.12	(10)	1.99

1 Professional fees include external audit, legal and reserve evaluation fees and other contract services.

For the three months ended December 31, 2022, gross G&A expense decreased by $0.9 million or 12%, compared to the same period in 2021. This decrease was primarily due to a $1.4 million or 24% decrease in salaries and benefits, as in the fourth quarter of 2021, the Company incurred additional costs due to an incentive program amendment.

For the year ended December 31, 2022, gross G&A expense increased by $1.1 million or 4%, compared to the same period in 2021. The increase was primarily due to higher corporate insurance rates, and a rise in donations, travel, and corporate events as operations normalized with the lifting of COVID-19 restrictions during the current year. The increase was partially offset by lower salaries and benefits due to an incentive program amendment which increased salaries and benefits in 2021.

Capitalized G&A expense varies with the composition and compensation levels of technical departments and their time attributed to capital projects. During the three months and year ended December 31, 2022, capitalized G&A expense increased by $0.2 million or 17%, and $0.4 million or 9% compared to the same periods of 2021, based on an increased employee focus on capital activity in the current year.

Optimization Fees

	Three Months Ended December 31,			Year Ended December 31,			
(Cdn$ thousands, except per boe)	2022	2021	% Change	2022	2021	% Change	2020
Optimization fees	—	13,665	(100)	—	19,708	(100)	670
Optimization fees - $/boe	—	5.35	(100)	—	1.94	(100)	0.06

Optimization fees relate to a business improvement project initiated through a third party consulting group that was terminated in the fourth quarter of 2021.

Transaction Costs

	Three Months Ended December 31,			Year Ended December 31,			
(Cdn$ thousands, except per boe)	2022	2021	% Change	2022	2021	% Change	2020
Transaction costs	3,059	—	100	19,080	—	100	—
Transaction costs - $/boe	1.13	—	100	1.63	—	100	—

On February 23, 2023, the Company completed a business combination agreement with DCRD, an affiliate of Riverstone. For the three months and year ended December 31, 2022 the Company incurred $3.1 million and $19.1 million, respectively, in transaction costs related to the business combination with DCRD.

Share-based Compensation Expense

(Cdn$ thousands, except per boe)	Three Months Ended December 31, 2022	2021	% Change	Year Ended December 31, 2022	2021	% Change	2020
Gross share-based compensation expense	**1,489**	3,872	(62)	**14,157**	18,658	(24)	8,352
Capitalized share-based compensation expense	**(387)**	(1,115)	(65)	**(4,113)**	(4,619)	(11)	(1,197)
Net share-based compensation expense	**1,102**	2,757	(60)	**10,044**	14,039	(28)	7,155
Net share-based compensation expense - $/boe	**0.41**	1.08	(62)	**0.86**	1.38	(38)	0.65

Changes in gross share-based compensation expense relate to the number of units granted, the timing of grants, the fair value of units on the grant date, the vesting period over which the related expense is recognized and the timing and quantity of forfeitures.

Gross share-based compensation decreased by $2.4 million or 62% and $4.5 million or 24% for the three months and year ended December 31, 2022, respectively, compared to the same periods of 2021. The decrease was primarily due to awards issued during 2021 which had accelerated vesting terms and were fully expensed by the second quarter of 2022.

Capitalized share-based compensation for the three months and year ended December 31, 2022 decreased by $0.7 million or 65%, and $0.5 million or 11% compared to the same periods of 2021 due to lower gross share-based compensation in 2022.

Finance Expense

(Cdn$ thousands, except per boe)	Three Months Ended December 31, 2022	2021	% Change	Year Ended December 31, 2022	2021	% Change	2020
Interest on term debt - cash	**—**	—	—	**1,785**	—	100	9,177
Interest on term debt - PIK	**2,247**	3,808	(41)	**12,833**	14,660	(12)	8,714
Total interest on term debt	**2,247**	3,808	(41)	**14,618**	14,660	—	17,891
Interest and fees on bank debt	**4,591**	1,087	322	**9,734**	5,979	63	16,961
Interest on lease obligation	**82**	38	116	**257**	181	42	286
Interest on EDC facility - letters of credit	**261**	359	(27)	**307**	419	(27)	711
Amortization of financing costs	**—**	—	—	**—**	—	—	1,459
Accretion of decommissioning liabilities	**166**	92	80	**581**	25	2,224	36
Total finance expense	**7,347**	5,384	36	**25,497**	21,264	20	37,344
Cash interest expense - $/boe	**1.82**	0.58	214	**1.03**	0.65	58	2.47
Non-cash interest and accretion expense - $/boe	**0.89**	1.53	(42)	**1.15**	1.45	(21)	0.93
Average principal debt outstanding during the period:							
Term debt (2020 Senior Notes)	**77,964**	132,033	(41)	**122,735**	125,823	(2)	
Bank debt (credit facility)	**127,898**	100,936	27	**105,656**	113,633	(7)	
Total average principal debt outstanding	**205,862**	232,969	(12)	**228,391**	239,456	(5)	

Finance expense is primarily comprised of interest incurred on the Company's term debt (2020 Senior Notes) and credit facility borrowings (bank debt).

Term Debt

The Company's term debt consists of the 2020 Senior Notes, which bear interest at 12% and include the option of paying interest as cash or as paid-in-kind ("PIK"). During the three months and year ended December 31, 2022, interest expense on term debt decreased by $1.6 million or 41% and a nominal amount, respectively, compared to the same periods of 2021. The decrease for the quarter was due to a lower outstanding principal amount on which the interest is calculated, as a result of the repayment of a portion of the 2020 Senior Notes during the third quarter of 2022. On an annual basis, the interest expense was consistent between 2021 and 2022 due to the increased PIK interest accumulation in the first three quarters of 2022, which offset reduced interest in the fourth quarter.

Bank Debt

During the three months and year ended December 31, 2022, interest expense and fees on bank debt increased by $3.5 million or 322%, and $3.8 million or 63% compared to the same periods of 2021. The increase for both periods was due to fees to amend the credit facility on December 15, 2022 and higher interest rates throughout 2022.

(Gain) Loss on Foreign Exchange

	Three Months Ended December 31,			Year Ended December 31,			
(Cdn$ thousands)	**2022**	2021	% Change	**2022**	2021	% Change	2020
Realized loss (gain) on foreign exchange	**168**	9	1,767	**2,425**	(9)	N/A	4
Unrealized (gain) loss on foreign exchange	**(1,112)**	(630)	77	**4,804**	(341)	N/A	813
(Gain) loss on foreign exchange	**(944)**	(621)	52	**7,229**	(350)	N/A	817

The Company's foreign exchange impacts primarily relate to term debt which is denominated in US dollars and translated into Canadian dollars at the end of each reporting period.

During the three months and year ended December 31, 2022, realized loss on foreign exchange increased $0.2 million and $2.4 million compared to the same periods of 2021. The increase for the year ended December 31, 2022 was due to the repayment of a portion of term debt which settled at a weaker exchange rate during the period. This was partially offset by a foreign exchange hedge entered into by the Company for the purpose of settling a portion of the term debt.

Relative to the US dollar, the Canadian dollar strengthened from 1.3707 at September 30, 2022 to 1.3544 at December 31, 2022. This resulted in a lower Canadian dollar liability for term debt and a corresponding unrealized foreign exchange gain of $1.1 million during the fourth quarter of 2022. Similarly, the Canadian dollar strengthened from 1.2741 at September 30, 2021 to 1.2678 at December 31, 2021. This resulted in a lower Canadian dollar liability for term debt and a corresponding unrealized foreign exchange gain of $0.6 million during the fourth quarter of 2021.

Relative to the US dollar, the Canadian dollar weakened from 1.2678 at December 31, 2021 to 1.3544 at December 31, 2022. This resulted in a higher Canadian dollar liability for term debt and a corresponding unrealized foreign exchange loss of $4.8 million for the year ended December 31, 2022. Conversely, the Canadian dollar strengthened from 1.2732 at December 31, 2020 to 1.2678 at December 31, 2021. This resulted in a lower Canadian dollar liability for term debt, and a corresponding unrealized foreign exchange gain of $0.3 million for the year ended December 31, 2021.

Depletion and Depreciation Expense

	Three Months Ended December 31,			Year Ended December 31,			
(Cdn$ thousands, except per boe)	**2022**	2021	% Change	**2022**	2021	% Change	2020
Depletion of developed and producing assets	**37,401**	30,235	24	**144,133**	122,623	18	132,859
Depreciation of corporate assets	**526**	467	13	**1,982**	1,481	34	1,590
Depreciation of right-of-use assets	**475**	186	155	**1,053**	741	43	735
Impairment	**—**	2,488	(100)	**—**	2,488	(100)	—
Total depletion and depreciation expense	**38,402**	33,376	15	**147,168**	127,333	16	135,184
Depletion and depreciation expense - $/boe	**14.14**	13.07	8	**12.57**	12.55	—	12.30

Depletion and depreciation reflect the development costs of Hammerhead's investments which are initially capitalized and then amortized to net income over the estimated useful lives of the assets. The Company's developed and producing assets are depleted using the unit-of-production method based on the estimated recoverable amount from total proved and probable ("2P") reserves determined in accordance with National Instrument 51-101. The depletion base consists of the historical net book value of capitalized costs plus estimated future development costs required to develop the Company's estimated 2P reserves. Depletion and depreciation rates are subject to change based on changes in the carrying value of the asset base, changes in future development costs, reserve updates and changes in production. Depletion expenses are calculated using depletion rates and production volumes applicable to each depletable asset.

For the three months ended December 31, 2022, depletion and depreciation expense increased $5.0 million or 15%, compared to the same period in 2021. The increase was due to a higher depletion rate, caused by an increase in future development costs and higher depletion of developed and producing assets, driven by higher production volumes.

For the year ended December 31, 2022, depletion and depreciation expense increased $19.8 million or 16%, compared to the same period in 2021. The increase primarily related to higher depletion of developed and producing assets, driven by higher production volumes.

(Gain) Loss on Warrant Revaluation

	Three Months Ended December 31,			Year Ended December 31,			
(Cdn$ thousands)	**2022**	2021	% Change	**2022**	2021	% Change	2020
(Gain) loss on warrant revaluation	**(77)**	6	N/A	**10,611**	96	10,953	(3,981)

The warrant liability was recorded at fair value upon inception and is reassessed at the end of each period, with changes in the estimated fair value recognized through income as a non-cash item. During the three months and year ended December 31, 2022, the Company incurred a nominal gain on warrant revaluation and a $10.6 million loss on warrant revaluation respectively, compared to a nominal loss on warrant revaluation for the same periods of 2021. The increased loss for the year ended December 31, 2022 relates to an increase in the value of warrants outstanding due to a rise in the Company's share price during the third quarter of 2022.

Funds from Operations

(Cdn$ thousands)	Three Months Ended December 31, 2022	2021	% Change	Year Ended December 31, 2022	2021	% Change	2020
Operating netback [1]	119,414	51,653	131	457,884	161,274	184	177,991
G&A expense	(5,543)	(6,641)	(17)	(22,268)	(21,565)	3	(21,838)
Optimization fees	—	(13,665)	(100)	—	(19,708)	(100)	(670)
Transaction costs	(3,059)	—	100	(19,080)	—	100	—
Cash interest expense	(4,934)	(1,484)	232	(12,083)	(6,579)	84	(27,135)
Realized foreign exchange (loss) gain	(168)	(9)	1,767	(2,425)	9	N/A	(4)
Other cash impacts [2]	379	455	(17)	2,939	1,022	188	1,143
Funds from operations [3]	106,089	30,309	250	404,967	114,453	254	129,487
(Cdn$ per boe)							
Operating netback [4]	43.96	20.22	117	39.10	15.90	146	16.20
G&A expense	(2.04)	(2.60)	(22)	(1.90)	(2.12)	(10)	(1.99)
Optimization fees	—	(5.35)	(100)	—	(1.94)	(100)	(0.06)
Transaction costs	(1.13)	—	100	(1.63)	—	100	—
Cash interest expense	(1.82)	(0.58)	214	(1.03)	(0.65)	58	(2.47)
Realized foreign exchange loss	(0.06)	—	100	(0.21)	—	100	—
Other cash impacts [2]	0.14	0.18	(22)	0.25	0.10	150	0.10
Funds from operations [5]	39.05	11.87	229	34.58	11.29	206	11.78
Weighted average common shares outstanding *(000s)*							
Basic	392,556	391,117	—	391,803	391,106	—	391,052
Diluted	1,058,515	952,281	11	961,751	391,106	146	728,575
Per common share - basic [6]	0.27	0.08	238	1.03	0.29	255	0.33
Per common share - diluted [7]	0.10	0.03	233	0.42	0.29	45	0.18

1 Operating netback is a non-GAAP measure. Oil and gas revenue is the most directly comparable GAAP measure to operating netback. Oil and gas revenue for the three months ended December 31, 2022 and 2021 were $198.7 million and $139.2 million, respectively. Oil and gas revenue for the years ended December 31, 2022, 2021, and 2020 were $844.6 million, $439.8 million, and $263.5 million respectively. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

2 Other cash impacts consist of treating and processing income, the Company's recoveries related to royalty interest and bad debt allowances.

3 Funds from operations is a non-GAAP measure. Net cash from operating activities is the most directly comparable GAAP measure for funds from operations. Net cash from operating activities for the three months ended December 31, 2022 and 2021 was $76.1 million and $33.5 million, respectively. Net cash from operating activities for the years ended December 31, 2022, 2021, and 2020 were $371.4 million, $121.1 million, and $119.7 million respectively. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

4 Operating netback per boe is a non-GAAP measure. Oil and gas revenue per boe is the most directly comparable GAAP measure to operating netback per boe. Oil and gas revenue for the three months ended December 31, 2022 and 2021 were $73.14/boe and $54.50/boe, respectively. Oil and gas revenue per boe for the years ended December 31, 2022, 2021 and 2020 were $72.13/boe, $43.34/boe, and $23.97/boe respectively. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

5 Funds from operations per boe is a non-GAAP measure. Net cash from operating activities per boe is the most directly comparable GAAP measure for funds from operations per boe. Net cash from operating activities per boe for the three months ended December 31, 2022 and 2021 was $28.03/boe and $13.13/boe, respectively. Net cash from operating activities for the years ended December 31, 2022, 2021, and 2020 were $31.71/boe, $11.93/boe, and $10.89/boe respectively. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

6 Funds from operations per common share - basic is a non-GAAP measure. Net cash from operating activities per common share - basic is the most directly comparable GAAP measure for funds from operations per common share - basic. Net cash from operating activities per common share - basic for the three months ended December 31, 2022 and 2021 was $0.19 and $0.09, respectively. Net cash from operating activities per common share - basic for the years ended December 31, 2022, 2021 and 2020 was $0.95, $0.31, and $0.31 respectively. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

7 Funds from operations per common share - diluted is a non-GAAP measure. Net cash from operating activities per common share - diluted is the most directly comparable GAAP measure for funds from operations per common share - diluted. Net cash from operating activities per common share - diluted for the three months ended December 31, 2022 and 2021 was $0.07 and $0.04, respectively. Net cash from operating activities per common share - diluted for the years ended December 31, 2022, 2021 and 2020 were $0.39, $0.31, and $0.16 respectively. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

The Company generated funds from operations of $106.1 million during the fourth quarter of 2022, a $75.8 million or 250% increase from the same quarter of 2021. The increase is primarily due to a $67.8 million increase in operating netback and a $13.7 million decrease in optimization fees, partially offset by a $3.5 million increase in cash interest expense.

The Company generated funds from operations of $405.0 million during the year ended December 31, 2022, a $290.5 million or 254% increase from the same period of 2021. The increase is primarily due to a $296.6 million increase in operating netback, a $19.7 million decrease in optimization fees and a $1.9 million increase in other cash impacts. This was partially offset by a $19.1 million increase in transaction costs, a $5.5 million increase in cash interest expense, a $2.4 million increase in realized foreign exchange loss, as well as a $0.7 million increase in G&A expense.

Adjusted Funds from Operations

	Three Months Ended December 31,			Year Ended December 31,			
(Cdn$ thousands)	2022	2021	% Change	2022	2021	% Change	2020
Funds from operations [1]	106,089	30,309	250	404,967	114,453	254	129,487
Optimization fees	—	13,665	(100)	—	19,708	(100)	670
Transaction costs	3,059	—	100	19,080	—	100	—
Realized foreign exchange loss (gain)	168	9	1,767	2,425	(9)	(27,044)	4
Other income, excluding transportation income	(379)	(455)	(17)	(2,939)	(1,022)	188	(1,143)
Adjusted funds from operations [1]	108,937	43,528	150	423,533	133,130	218	129,018
Weighted average common shares outstanding (000s)							
Basic	392,556	391,117	—	391,803	391,106	—	391,052
Diluted	1,058,515	952,281	11	961,751	391,106	146	728,575
Per common share - basic [1]	0.28	0.11	155	1.08	0.34	218	0.33
Per common share - diluted [1]	0.10	0.05	100	0.44	0.34	29	0.18

1 Funds from operations and adjusted funds from operations are non-GAAP measures. Net cash from operating activities is the most directly comparable GAAP measure for funds from operations and adjusted funds from operations. Net cash from operating activities for the three months ended December 31, 2022 and 2021 was $76.1 million and $33.5 million, respectively. Net cash from operating activities for the years ended December 31, 2022, 2021, and 2020 were $371.4 million, $121.1 million, and $119.7 million respectively. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

Net Profit (Loss)

	Three Months Ended December 31,			Year Ended December 31,			
(Cdn$ thousands, except per share)	2022	2021	Change	2022	2021	Change	2020
Net profit (loss)	67,298	37,139	81	225,100	(71,821)	N/A	53,410
Net profit (loss) attributable to ordinary equity holders - basic	60,584	31,344	93	199,865	(93,601)	N/A	34,566
Weighted average common shares outstanding - basic *(000s)*	392,556	391,117	—	391,803	391,106	—	391,052
Per common share - basic	0.15	0.08	88	0.51	(0.24)	N/A	0.09
Net profit (loss) attributable to ordinary equity holders - diluted	60,508	31,359	93	199,865	(93,601)	N/A	34,669
Weighted average common shares outstanding - diluted *(000s)*	1,058,515	952,281	11	961,751	391,106	146	728,575
Per common share – diluted	0.06	0.03	100	0.21	(0.24)	N/A	0.05

(Cdn$ thousands)	
Net profit, three months ended December 31, 2021	37,139
Increase from funds from operations [1]	75,780
Add (deduct) change in non-cash items:	
Increase in deferred income tax expense	(31,720)
Decrease in unrealized gain on risk management contracts	(12,581)
Increase in depletion, depreciation and impairment expense	(5,026)
Decrease in share based compensation expense	1,655
Decrease in non-cash finance costs	1,486
Other	565
Net profit, three months ended December 31, 2022	67,298

1 Funds from operations is a non-GAAP measure. Net cash from operating activities is the most directly comparable GAAP measure for funds from operations. Net cash from operating activities for the three months ended December 31, 2022 and 2021 was $76.1 million and $33.5 million, respectively. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

The Company reported a net profit of $67.3 million for the three months ended December 31, 2022, compared to a net profit of $37.1 million in the same period of 2021. The $30.2 million improvement was primarily due to a $75.8 million increase in funds from operations, partially offset by a $31.7 million increase in deferred income tax expense and a $12.6 million decrease in unrealized gain on risk management contracts. The improvement was further driven by the remaining non-cash impacts of $1.3 million as outlined in the table above.

(Cdn$ thousands)	
Net loss, year ended December 31, 2021	(71,821)
Increase from funds from operations [1]	290,514
Add (deduct) change in non-cash items:	
Increase in unrealized gain on risk management contracts	54,761
Loss on property disposition	13,813
Increase in deferred income tax expense	(31,720)
Increase in depletion and depreciation expense	(19,835)
Increase in unrealized loss on foreign exchange	(5,145)
Decrease in share based compensation expense	3,995
Change in fair value of warrants	(10,515)
Other	1,053
Net profit, year ended December 31, 2022	225,100

1 Funds from operations is a non-GAAP measure. Net cash from operating activities is the most directly comparable GAAP measure for funds from operations. Net cash from operating activities for the years ended December 31, 2022 and 2021 were $371.4 million and $121.1 million, respectively. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

The Company reported a net profit of $225.1 million for the year ended December 31, 2022, compared to a net loss of $71.8 million in the same period of 2021. The $296.9 million improvement was primarily due to a $290.5 million increase in funds from operations and a $54.8 million increase in unrealized gain on risk management contracts. This was partially offset by a $31.7 million increase in deferred income tax expense and the remaining non-cash impacts of $16.6 million as outlined in the table above.

Deferred Income Taxes

Deferred income taxes reflect the net tax effect of temporary differences between the carrying amount of assets and liabilities for financial reporting purposes and the amounts for income tax purposes. As at December 31, 2022, the Company recognized a deferred tax liability of $31.7 million. As at December 31, 2021, the Company had a deferred tax asset of $32.1 million that was not recognized in the financial statements due to the uncertainty regarding future taxable profits against which losses can be offset. The Company does not anticipate paying current income taxes until 2025, based on current strip pricing.

The Company's estimated consolidated income tax pools are summarized as follows:

(Cdn$ thousands)	**December 31, 2022**	December 31, 2021
Canadian oil and gas property expense	**100,058**	109,861
Canadian development expense	**348,313**	258,454
Canadian exploration expense	**207,272**	207,104
Non-capital losses [1]	**270,352**	343,879
Undepreciated capital cost pools	**532,314**	549,896
Debt and share issuance costs	**3,647**	4,710
Total	**1,461,956**	1,473,904

1 These non-capital losses begin to expire after 2034.

Capital Expenditures

Net cash used in investing activities is the most directly comparable GAAP measure for capital expenditures, which is a non-GAAP measure. Net cash used in investing activities for the three months ended December 31, 2022 and 2021 was $145.6 million and $42.2 million, respectively. Net cash used in investing activities for the years ended December 31, 2022 and 2021 were $368.2 million and $91.2 million, respectively. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

	Three Months Ended December 31, 2022			Year Ended December 31,			
(Cdn$ thousands)	**2022**	2021	% Change	**2022**	2021	% Change	2020
Drilling and completion	**127,056**	54,305	134	**248,141**	104,051	138	63,941
Equipment, facilities and pipelines	**42,989**	9,470	354	**114,440**	22,742	403	21,012
Workovers and maintenance capital	**1,503**	3,319	(55)	**12,830**	5,851	119	5,757
Land	**—**	—	—	**1,311**	—	100	—
Geological and geophysical	**5**	—	100	**168**	1	16,700	45
Other [1]	**2,116**	1,291	64	**6,986**	5,899	18	3,607
Capital expenditures [2]	**173,669**	68,385	154	**383,876**	138,544	177	94,362

1 Other includes capitalized salaries and benefits and corporate capital expenditures.
2 Net cash used in investing activities is the most directly comparable GAAP measure for capital expenditures, which is a non-GAAP measure. Net cash used in investing activities for the three months ended December 31, 2022 and 2021 was $145.6 million and $42.2 million, respectively. Net cash used in investing activities for the years ended December 31, 2022, 2021, and 2020 were $368.2 million, $91.2 million, and $113.3 million respectively. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

Capital expenditures for the three months ended December 31, 2022 were $173.7 million, up $105.3 million from the comparative period of 2021.

For the three months ended December 31, 2022, the Company incurred approximately $129.8 million in its Karr area, primarily related to the completion and tie-in of a nine gross (nine net) well pad, which came on-stream in December 2022, and a portion of the drill and tie-in of a seven gross (seven net) well pad. The Company also spent approximately $23.8 million in its Gold Creek area, of which the majority related to the drill, completion and tie-in of a three gross (three net) well pad, which came on-stream in December 2022. Remaining funds incurred were related to various non-well infrastructure and the drill, completion and partial tie-in of a non-operated three gross (1.05 net) well pad.

For the three months ended December 31, 2021, the Company incurred approximately $38.3 million in its Gold Creek area, of which the majority related to continuing the drill, completion and tie-in of a six gross (six net) well pad which came on-stream in January 2022, the completion and tie-in of a six gross (six net) well pad which came on-stream in October 2021, and initiating drills for a four gross (four net) well extension off that same pad. The Company also incurred approximately $30.0 million in its Karr area, the majority of which related to the drill, completion and tie-in of a three gross (three net) well pad, which came on-stream in January 2022. The remaining funds incurred in Karr were primarily related to initial drilling costs and pipeline infrastructure on another four gross (four net) well pad, as well as construction, workover and maintenance capital.

Capital expenditures for the year ended December 31, 2022 were $383.9 million, up $245.3 million from the comparative period of 2021.

For the year ended December 31, 2022, the Company incurred approximately $249.9 million in its Karr area, primarily related to the drill, completion and tie-in of two pads with a combined 13 gross (13 net) wells and a portion of the drill and tie-in of 10 gross (8.05 net) wells across two pads. The remaining spend in the Karr area related to battery, facility and pipeline expansion projects, as well as minor costs on workover and maintenance capital. The Company also incurred approximately $97.6 million in its Gold Creek area, the majority of which related to the drill, complete and tie-in of three pads with a combined 12 gross (12 net) wells. The remaining funds incurred in Gold Creek were primarily related to the drill, complete and tie-in of two gross (two net) water disposal wells and workover and maintenance capital.

For the year ended December 31, 2021 the Company incurred approximately $74.4 million in its Gold Creek area, of which the majority related to the drill, completion and tie-in of two pads, each with six gross (six net) wells, which came on-stream in October 2021 and January 2022. The remaining funds incurred in Gold Creek were primarily related to water disposal facilities and initiating drills on a four gross (four net) well extension from an existing pad. The Company also incurred approximately $53.7 million in its Karr area, the majority of which related to the drill, completion and tie-in of a three gross (three net) well pad which came on-stream in January 2022, as well as the completion and tie-in of a two gross (two net) well pad which came on-stream in the first quarter of 2021. The remaining funds incurred in Karr were primarily related to initiating drilling on a four gross (four net) well pad, completion of one gross (one net) well, and completion and tie-in of one gross (0.5 net) well under the Company's farm-out agreement.

Net Well Information [1]

	Three Months Ended December 31,		Year Ended December 31,	
(Number of wells)	**2022**	2021	**2022**	2021
Spud	**9.00**	10.00	**29.05**	19.00
Rig released	**9.70**	10.00	**29.05**	17.00
Completed	**12.00**	14.00	**26.00**	17.50
Wells brought on-stream [2]	**12.00**	6.00	**34.00**	14.85

1 Well counts include development Montney wells, shown on a net well basis. The Company has no exploratory wells and drilled one net dry development well during the three months and year ended December 31, 2022.

2 On-stream dates are based on the first production date after the well is tied-in to the permanent well site facilities. Wells brought on-stream may include wells drilled and/or completed in a prior period.

As at December 31, 2022, the Company had 162.0 gross (157.35 net) wells capable of producing. As at December 31, 2021, the Company had 132.0 gross (129.3 net) wells capable of producing. Of the total wells capable of producing, five gross (five net) wells were classified as gas wells, with the remainder as oil as at December 31, 2022 and 2021.

Land Acreage

	December 31, 2022			December 31, 2021		
	Gross acres	**Net acres**	**Working interest percentage**	Gross acres	Net acres	Working interest percentage
Montney	**118,560**	**106,800**	**90**	126,738	113,730	90

Corporate Outlook and Guidance

Hammerhead Energy's 2023 capital program is development-focused with a continuous 2-rig program expected to drill approximately 40 wells. HEI is continuing to increase its drilling focus on the North and South Karr assets with plans to allocate approximately 75% of drilling and completion activity to Karr with the remaining 25% at Gold Creek. Hammerhead Energy expects significant production and cash flow growth while targeting free funds flow neutrality in 2023 notwithstanding $110.1 million in infrastructure expenditures at North and South Karr in the year. Significant investment in field infrastructure in 2022 and 2023 will maximize operational control, minimize cash costs and allow for “half cycle” economics from 2024 forward.

HEI expects to achieve an inflection point in material free funds flow generation in Q4 2023 as major infrastructure expansion capital expenditures will be largely complete. Hammerhead Energy plans to roughly double production in the next three years (as compared to the 2022 annual average) while generating significant amounts of free funds flow starting in the fourth quarter of this year.

The Company's 2023 annual guidance is outlined below:

Forward looking information [1]		**2023 guidance**
Annual average production	*boe/d*	**40,200**
Crude oil and field condensate	*%*	**33**
Natural gas liquids ("NGLs")	*%*	**12**
Natural gas	*%*	**55**
Expenses		
Royalties	*%*	**13**
Operating	*$/boe*	**8.50**
Transportation	*$/boe*	**6.50**
Net general and administrative	*$/boe*	**1.60**
Cash interest and financing	*$/boe*	**1.40**
Cash taxes	*$/boe*	**—**
Capital expenditures [2]	*$MM*	**525**

1 Forward looking information are not guarantees of future performance and involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated with forward looking information. Refer to the subsection "Forward-Looking Statements".

2 Net cash used in investing activities is the most directly comparable GAAP measure for capital expenditures, which is a non-GAAP measure.Net cash used in investing activities for the years ended December 31, 2022, 2021, and 2020 were $368.2 million, $91.2 million, and $113.3 million respectively. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

Hammerhead is targeting greater than 25% production growth in 2023, with oil production growth expected to exceed 40%. HHR expects to achieve these results on an internally funded basis.

Hammerhead's actual results could differ materially from this outlook and guidance as a result of volatility in the market prices for oil, gas and NGLs, well performance, and success of the capital program.

Significant Project Update

Hammerhead is currently planning and executing on over $100.0 million of pipeline and facility expansions within both its North and South Karr areas in order to accommodate the Company's expected growth in production. In the North Karr location, following an update to current project estimates, the Company estimates capital expenditures of $42.0 million, an increase from $39.4 million as estimated in Q3 of 2022, to expand its current facility, which was completed in Q1 2023. These expenditures were financed through cash flow and capital sources. As at December 31, 2022, the Company had incurred costs of $33.7 million related to its North Karr facility. In South Karr, the Company is planning to build a new facility. The project is estimated to cost $61.0 million and is currently targeted to be on-stream by the fourth quarter of 2023. These expenditures will also be financed through cash flow and capital sources. As at December 31, 2022, Hammerhead had incurred approximately $9.0 million related to the new South Karr facility project.

The Company has embarked on a decarbonization investment campaign across its asset base with the Company's CCS program. The program is expected to drive a reduction in Scope 1 and Scope 2 emissions of approximately 79% on an absolute basis and approximately 89% on a per boe basis by 2029, as compared to 2021 levels, assuming that each of Hammerhead's oil batteries are converted to CCS from 2024 through 2029.

Prior to any construction or sequestration activity, the Company must receive final approval from the Alberta Department of Energy. The timeframe of approval is dependent on regulatory review and will be received by the second quarter of 2023 at the earliest. There is no guarantee that such approval will be received on this timeline or at all. Presently, Hammerhead does not have the right to sequester carbon emissions nor is it authorized to generate credits or monetize the emissions sequestered.

The key milestones of the project, once approval from the Department of Energy is received include, drilling a deep CO2 disposal well and confirming adequate injectivity, finalizing the design engineering and lastly obtaining final approval from the Hammerhead Board to proceed with the first battery pilot project. As of September 30, 2022, the Company had planned to drill the disposal well, finalize engineering plans, and following regulatory approval, obtain board approval on the first battery pilot project in 2023. As at December 31, 2022, the Company expects regulatory approval to occur later in 2023, and as a result, plans to drill the disposal well and finalize the engineering designs in 2024. Upon successful testing of the CO2 disposal well, the Company will present the pilot project for approval to the Hammerhead Board in 2024. Following the Hammerhead Board's approval, the Company will initiate construction of the pilot battery, with equipment purchases occurring in 2024. Hammerhead expects to spend between $60.0 million to $75.0 million to build facilities, pipeline and disposal well assets at the pilot battery in Gold Creek. The remaining capital will be spent in the following five years; constructing carbon capture and storage facilities on Hammerhead's other four batteries. The total anticipated spend on the project is $240.0 million. As at December 31, 2022, the Company has not incurred costs or signed contractual commitments related to the CCS program.

Capital Resources and Liquidity

Capital Resources

Bank Debt

(Cdn$ thousands)	**December 31, 2022**	December 31, 2021
Syndicated facility	**164,800**	106,300
Operating facility	**15,000**	—
Total bank debt outstanding [1]	**179,800**	106,300

1 Undrawn bank debt capacity was $170.2 million as of December 31, 2022 (December 31, 2021 - $68.7 million).

The Company's bank debt is held in a credit facility with a syndicate of lenders. On June 9, 2022, the Company amended its existing Credit Facilities pursuant to the 2022 Credit Agreement. Under the amended agreement, the maximum aggregate principal amount of the Credit Facilities was increased to $300.0 million, consisting of a $280.0 million revolving syndicated facility and a $20.0 million operating facility.

On December 15, 2022, the Company further amended its existing credit facility, increasing the aggregate principal borrowing base to $350.0 million, consisting of a $330.0 million revolving syndicated facility and a $20.0 million operating facility. The amended credit facility agreement has a term date of May 31, 2023 and a maturity date of May 31, 2024, with an option to extend for an additional 364 days at the lenders' discretion. The total outstanding balance is due on the maturity date.

Under the amended credit facility, determination of the borrowing base is made by the lenders at their sole discretion, and is subject to re-determinations semi-annually as of May 31st and November 30th of the respective year.

As at December 31, 2022, Hammerhead was compliant with all covenants and cross default clauses stated in the amended credit facility agreement. Covenants include reporting requirements and limitations on excess cash, indebtedness, equity issuances, acquisitions, dispositions, hedging, encumbrances, asset retirement obligations, as well as other standard business operating covenants. The Company is not subject to financial covenants. The lenders have first lien on all of the Company and its subsidiary's assets.

Amounts borrowed in Canadian dollars under the amended credit facility bear interest based on the referenced Canadian prime lending rate or the bankers' acceptance rate in effect, at the Company's option, plus an applicable margin or fee, respectively. The applicable rate is determined by the ratio of first lien indebtedness to earnings before interest, taxes, depreciation, depletion and amortization. The amended credit facility also includes standby fees on balances not drawn.

The following ranges are the applicable prime margin, bankers' acceptance and standby fees:

	Margin on Canadian Prime Rate	**Bankers' Acceptance Fee**	**Standby Fee**
Credit facility	1.75% - 5.25%	2.75% - 6.25%	0.69% - 1.56%

Term Debt

(Cdn$ thousands)	December 31, 2022	December 31, 2021
2020 Senior Notes – outstanding principal	120,648	120,648
Principal repayment, net of outstanding PIK interest [1]	(42,414)	23,374
Foreign exchange revaluation [2]	698	(9,275)
Total term debt	**78,932**	134,747

1 The Company repaid $78.6 million of principal on its 2020 Senior Notes. The repayment is netted with the accumulated PIK interest of $32.1 million. Total accrued unpaid PIK as at December 31, 2022 is $4.1 million.

2 The term debt is issued in US dollars and are revalued to Canadian dollars at each reporting period, using the period end foreign exchange rate.

Term debt consists of the 2020 Senior Notes, which have a maturity date of July 10, 2024. The notes bear interest at 12% per annum and provide the option of paying interest as cash or as paid-in-kind ("PIK"). PIK interest is added to the principal balance and is due on maturity.

On September 26, 2022, the Company repaid, at par value, US$59.3 million of principal and accrued interest on its 2020 Senior Notes, reducing the aggregate principal balance outstanding down to US$56.5 million. On settlement of US$57.9 million of principal, $5.2 million of the accumulated unrealized loss recognized was realized as a foreign exchange loss on the statement of profit (loss). The realized foreign exchange loss on debt was offset with a $3.2 million realized foreign exchange gain from the settlement of a foreign currency hedge.

If a change of control or a specified asset disposition occurs, each holder of the 2020 Senior Notes has the right to require Hammerhead to purchase all or any part of the holder's 2020 Senior Notes for cash, at a price equal to 101% of the principal amount repurchased plus accrued and unpaid interest ("the Put Option"). While the Put Option met the definition of an embedded derivative, it is considered to be closely related to the underlying value of the term debt.

As at December 31, 2022, the Company was in compliance with all covenants related to term debt. There are no maintenance financial covenants related to the 2020 Senior Notes; however, there are standard business operating covenants, as well as covenants that may limit Hammerhead's ability to incur additional debt.

Export Development Canada ("EDC") Letters of Credit

The Company has guaranteed letters of credit in both Canadian and US dollars. As at December 31, 2022 and December 31, 2021, the Company's Canadian dollar denominated letters of credit were guaranteed through EDC and totaled $13.8 million and the Company's US dollar denominated guaranteed letters of credit totaled $US0.7 million (Cdn$0.9 million).

June 2020 Equity Commitment

On June 17, 2020, the Company entered into an investment agreement (the "June 2020 Equity Commitment") with an affiliate of its controlling shareholder. Under the June 2020 Equity Commitment, the Company agreed to issue up to 600.0 million Series IX first preferred shares and 33.7 million common share purchase warrants, in exchange for aggregate cash proceeds of up to $300.0 million.

On February 5, 2021 the Company received an equity investment of $33.7 million cash proceeds in exchange for the issuance of 67.4 million Series IX first preferred shares.

Upon the close of the business combination agreement with DCRD on February 23, 2023, the June 2020 Equity Commitment was terminated.

December 2020 Equity Commitment

On December 8, 2020, the Company entered into an investment agreement (the "December 2020 Equity Commitment") with an affiliate of one of its shareholders ("the Investor"). Under the December 2020 Equity Commitment, the Company agreed to issue up to 23.1 million Series IX first preferred shares and 1.3 million common share purchase warrants, in exchange for aggregate cash proceeds of up to $11.6 million.

On February 5, 2021 the Company received an additional equity investment of $1.3 million cash proceeds in exchange for the issuance of 2.6 million Series IX first preferred shares.

Upon the close of the business combination agreement with DCRD on February 23, 2023, the December 2020 Equity Commitment was terminated.

Share Capital

On February 23, 2023, the Company completed a business combination agreement with DCRD, an affiliate of the Company's controlling shareholder, Riverstone. Pursuant and subsequent to the business combination, Hammerhead Resources Inc. was renamed Hammerhead Resources ULC, a wholly owned subsidiary of HEI. As a result of the combination, HEI issued a combined total of 90,778,275 common shares and 28,549,991 warrants to the shareholders of Hammerhead and DCRD.

HEI is authorized to issued an unlimited number of common shares. As at March 28, 2023, HEI had 90,927,765 common shares, 28,549,991 warrants, 5,187,659 RSUs, and 664,328 options issued and outstanding.

Liquidity

Capital Management and Liquidity

Hammerhead's objective when managing capital is to maintain a flexible capital structure and sufficient liquidity to meet its financial obligations and to execute its business plans. The Company considers its capital structure to include shareholders' equity, the funds available under outstanding debt agreements, funds from operations and working capital. Modifications to Hammerhead's capital structure can be accomplished through issuing common and preferred shares, issuing new debt, adjusting capital spending and acquiring or disposing of assets, though there is no certainty that any of these additional sources of capital would be available if required.

The primary sources of cash for Hammerhead during the year ended December 31, 2022 were funds from operations and draws on the bank debt. The primary uses of cash were the repayment of a portion of the outstanding term debt and the Company's capital development program. The primary sources of cash for Hammerhead during the year ended December 31, 2021 were funds from operations, equity proceeds from the 2020 Investment agreement, and proceeds from disposition of non-core properties. The primary uses of cash were the Company's capital development program, as well as repayment of bank debt.

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. The Company addresses its liquidity risk through its capital management of cash, adjusted working capital, Credit Facility capacity, and equity issuances along with its planned capital expenditure program. The Company has determined that both its current and long term financial obligations, including Commitments and Contractual Obligations (see subsection below), are adequately funded from the available borrowing capacity on the Credit Facility and from funds from operations.

Adjusted Working Capital Deficit and Available Funding

Adjusted working capital provides useful information by highlighting net assets that are expected to be realized, or net liabilities that are expected to be settled, within the current operating cycle. Available funding allows management and other users to evaluate the Company's short term liquidity, and its capital resources available at a point in time. Available funding is not a standardized financial measure under IFRS and therefore may not be comparable with the calculation of similar measures disclosed by other entities.

(Cdn$ thousands)	**December 31, 2022**	December 31, 2021
Adjusted working capital deficit [1]	**(32,915)**	(52,443)
Debt capacity	**170,200**	68,700
Equity commitment [2]	**172,700**	172,700
Available funding [3]	**309,985**	188,957

1 This is a capital management measure. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures" in this MD&A for more information on this capital management measure.

2 See Capital Resources section within this MD&A for a breakdown of the remaining equity commitment under the June and December 2020 Equity Commitment.

3 Available funding is a non-GAAP measure. Working capital deficit is the most directly comparable GAAP measure for available funding. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

Upon the close of the business combination agreement with DCRD on February 23, 2023, the June 2020 equity commitment and the December 2020 equity commitment were terminated.

Net Debt, Adjusted EBITDA and Net Debt to Adjusted EBITDA

Adjusted EBITDA indicates the Company's ability to generate funds from its asset base on a continuing basis, for future development of its capital program and settlement of financial obligations. Hammerhead's short-term capital management objective is to fund its capital expenditures using primarily funds from operations, noting value-creating activities may be financed with a combination of funds from operations and other sources of capital. Net debt is used to assess and monitor liquidity at a point in time, while net debt to adjusted EBITDA assists the Company in monitoring its capital structure and financing requirements. Net debt, adjusted EBITDA and net debt to adjusted EBITDA are not standardized measures under IFRS and therefore may not be comparable with the calculation of similar measures disclosed by other entities.

(Cdn$ thousands)	December 31, 2022	December 31, 2021
Bank debt	179,800	106,300
Term debt	78,932	134,747
Adjusted working capital deficit [1]	32,915	52,443
Total net debt [2]	291,647	293,490
Adjusted EBITDA [3]	435,616	140,236
Net debt to adjusted EBITDA [4]	0.7	2.1

1 Adjusted working capital deficit is a capital management measure. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

2 Net debt is a non-GAAP measure. The Company's third party debt obligations of the bank debt and the term debt are the most directly comparable GAAP measures for net debt. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

3 Adjusted EBITDA is a non-GAAP measure. Net profit before income tax is the most directly comparable GAAP measure to adjusted EBITDA. For the years ended December 31, 2022 and 2021, the net profit (loss) before income tax was $256.8 million and a loss of $71.8 million, respectively. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

4 Net debt to adjusted EBITDA is a non-GAAP measure, derived from the net debt non-GAAP measure and adjusted EBITDA non-GAAP measure, where the directly comparable GAAP measures are the Company's debt obligations of bank debt and term debt, and the Company's net profit (loss), respectively. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

Free Funds Flow

Free funds flow is calculated as adjusted funds from operations less capital expenditures and settlement of decommissioning obligations. Management believes free funds flow provides an indication of funds the Company has available for future capital allocation decisions such as the repayment of debt or increased capital spending.

	Three Months Ended December 31,		Year Ended December 31,		
(Cdn$ thousands)	2022	2021	2022	2021	2020
Adjusted funds from operations [1]	108,937	43,528	423,533	133,130	129,018
Capital expenditures [2]	(173,669)	(68,385)	(383,876)	(138,544)	(94,362)
Settlement of decommissioning obligations	—	—	(123)	—	—
Free funds flow [1]	(64,732)	(24,857)	39,534	(5,414)	34,656

1 Adjusted funds from operations and free funds flow are non-GAAP measures. Net cash from operating activities is the most directly comparable GAAP measure for adjusted funds from operations and free funds flow. Net cash from operating activities for the three months ended December 31, 2022 and 2021 was $76.1 million and $33.5 million, respectively. Net cash from operating activities for the years ended December 31, 2022, 2021 and 2020 was $371.4 million, $121.1 million, and $119.7 million respectively. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

2 Net cash used in investing activities is the most directly comparable GAAP measure for capital expenditures, which is a non-GAAP measure. Net cash used in investing activities for the three months ended December 31, 2022 and 2021 was $145.6 million and $42.2 million, respectively. Net cash used in investing activities for the years ended December 31, 2022, 2021, and 2020 were $368.2 million, $91.2 million, and $113.3 million respectively. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

The Company generated adjusted funds from operations of $108.9 million during the fourth quarter of 2022, and capital expenditures totaled $173.7 million, which combined for negative free funds flow of $64.7 million, a decrease of $39.9 million from the fourth quarter of 2021. This decrease is due to the timing and magnitude of the 2022 capital spending program, where a significant portion of the annual 2022 capital spending occurred in the fourth quarter.

The Company generated adjusted funds from operations of $423.5 million during the year ended December 31, 2022, a $290.4 million increase from the same period of 2021. Capital expenditures for the year ended December 31, 2022 were $383.9 million, up $245.3 million from the comparative period of 2021. Net of $0.1 million in decommissioning settlements, free funds flow in 2022 was $39.5 million, an increase of $44.9 million from the prior year. In 2022, the Company allocated free funds to reduce net debt.

Commitments and Contractual Obligations

The Company enters into commitments and contractual obligations in the normal course of operations. Commitments include short-term drilling rig contracts, operating costs for office leases, and firm transportation and processing agreements. Although transportation and processing commitments are required to ensure access to sales markets, the Company actively manages the commitment portfolio to ensure firm commitment levels are in line with future development plans and diversified to multiple sales markets. The Company's firm transportation and processing agreements are terminable in very limited circumstances. If the Company does not meet the commitments with produced volumes, it will be obligated to pay the commitment.

Contractual obligations comprise of liabilities to third parties incurred for the purpose of managing the Company's capital structure, the liability portion of office building leases, risk management contracts, and decommissioning liabilities. Hammerhead does not have guarantees or off-balance sheet arrangements other than as disclosed.

The following table is a summary of the Company's commitments and contractual obligations as at December 31, 2022.

(Cdn$ thousands)	1 Year	2-3 Years	4-5 Years	Thereafter	Total
Firm transportation & processing	99,606	208,173	158,644	188,176	654,599
Office buildings [1]	972	1,658	1,632	—	4,262
Drilling services	2,100	900	—	—	3,000
Total annual commitments	102,678	210,731	160,276	188,176	661,861
Accounts payable and accrued liabilities	135,547	—	—	—	135,547
Bank indebtedness – principal [2]	—	179,800	—	—	179,800
Bank indebtedness – interest	13,737	5,579	—	—	19,316
Term debt – principal	—	89,080	—	—	89,080
Term debt – PIK interest	—	5,196	—	—	5,196
Lease obligations [3]	1,405	2,398	1,899	1	5,703
Risk management contracts	7,286	—	—	—	7,286
Decommissioning obligations [3]	—	—	—	30,197	30,197
Total contractual obligations	157,975	282,053	1,899	30,198	472,125
Total future payments	260,653	492,784	162,175	218,374	1,133,986

1 Relates to non-lease components and non-indexed variable payments.
2 The Company's credit facility is subject to a semi-annual borrowing base review at the sole discretion of the lenders. See Capital Resources - Bank Debt in this MD&A for additional information.
3 These values are undiscounted and will differ from the amounts presented in the 2022 Financial Statements.

Quantitative and Qualitative Disclosures about Market Risk

Hammerhead is exposed to a number of market risks, including changes in market prices, such as commodity prices, foreign exchange rates and interest rates that may affect the Company's income or the value of its financial instruments. The objective of market risk management is to manage and control market risk exposure within acceptable parameters, while optimizing the return. For the fair value on the Company's risk management contracts, see Commodity Price Risk section below.

Currency Risk

Currency risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. The Company's petroleum and natural gas sales are conducted in Canada and are denominated in Canadian dollars.

The Company is also exposed to currency risk in relation to its 2020 Senior Notes, which are denominated in US dollars. A 10% strengthening (weakening) of the US dollar would have contributed a $7.9 million increase (decrease) to the Company's net profit (loss) before tax for the year ended December 31, 2022 (year ended December 31, 2021 – $13.5 million, and year ended December 31, 2020 - $12.0 million), resulting from the revaluation of the 2020 Senior Notes.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate risk related to borrowings drawn under the credit facility, as the interest charged on the credit facility fluctuates with floating interest rates.

An increase (decrease) in the interest rates of 1% would have increased (decreased) interest expense by $1.1 million for the year ended December 31, 2022 (year ended December 31, 2021 - $1.1 million, and year ended December 31, 2020 - $2.4 million).

Commodity Price Risk

The Company's operational results and financial condition are largely dependent on the commodity price received for its oil and natural gas production. Commodity prices have fluctuated widely in recent years due to global and regional factors including supply and demand fundamentals, inventory levels, weather, economic and geopolitical factors.

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted not only by the relationship between the Canadian and United States dollars but also worldwide economic events that influence supply and demand.

Hammerhead enters into risk management contracts to manage its exposure to commodity price fluctuations, which have served to protect and provide certainty on a portion of the Company's cash flows. All risk management contracts entered into by Hammerhead are entered into for purposes other than trading purposes. Risk management contracts are valued using valuation techniques with observable market inputs. The most frequently applied valuation techniques include forward pricing and swap models using present value calculations and third-party option valuation models. The models incorporate various inputs including the foreign exchange spot and forward rates, and forward curves and volatilities of the underlying commodity.

See the subsection Risk Management Contracts for the fair value of all risk management contracts outstanding by commodity type, a summary of the terms of all outstanding risk management contracts, and a breakdown of all realized and unrealized gains and losses on risk management contracts recognized during periods presented in this MD&A.

HHR manages the risks associated with changes in commodity prices by entering into a variety of risk management contracts. The Company assesses the effects of movement in commodity prices on income before tax. When assessing the potential impact of these commodity price changes, the Company believes a 10% volatility is a reasonable measure.

A 10% change in commodity prices would have resulted in the following impact to the Company's unrealized gain (loss) on risk management contracts and net profit (loss) before tax, assuming all other variables including the Canadian dollar to United States dollar exchange rate, remained constant:

Year Ended December 31, 2022	**Increase 10%**	**Decrease 10%**
(Cdn$ thousands)		
Crude oil	**(6,276)**	**6,276**
Natural gas	**(11,359)**	**11,450**

Year Ended December 31, 2021	Increase 10%	Decrease 10%
(Cdn$ thousands)		
Crude oil	(18,559)	18,559
Natural gas	(7,960)	8,889
NGLs	(1,205)	(1,205)

Year Ended December 31, 2020	Increase 10%	Decrease 10%
(Cdn$ thousands)		
Crude oil	(12,348)	12,348
Natural gas	(5,847)	5,847

Related Party Transactions

All related party transactions occurred in the normal course of operations.

Key management personnel

Key management personnel are those persons having authority and responsibility for planning, directing and controlling the activities of the Company. Hammerhead has determined that the key management personnel of the Company consists of its officers and directors. The following table summarizes compensation paid or payable to key management personnel of the Company:

(Cdn$ thousands)	**December 31, 2022**	December 31, 2021	December 31, 2020
Salaries, bonuses, benefits and director fees	**5,584**	4,852	4,101
Share-based compensation	**7,334**	9,071	5,259
Total key management compensation	**12,918**	13,923	9,360

During the year ended December 31, 2022, key management personnel were granted an aggregate of 14.9 million RSUs (December 31, 2021 – 19.5 million and December 31, 2020 - nil) and nil stock options (December 31, 2021 - nil and December 31, 2020 - 0.6 million stock options with an average exercise price of $0.50 per share).

At December 31, 2022, $5.6 million in limited recourse loans previously advanced to key management personnel remained outstanding (December 31, 2021 - $5.6 million). The loans bear interest at a fixed rate of 1% per annum, which resulted in the receipt of $0.1 million in cash interest received by the Company from key management personnel during the year (December 31, 2021 – $0.1 million and December 31, 2020 - $0.1 million).

On September 26, 2022, the Company announced that it had entered into a business combination agreement with DCRD, an affiliate of Riverstone, to form a publicly traded company listed on the Nasdaq and TSX. The agreement closed on February 23, 2023. Upon close of the arrangement, the limited recourse loans were terminated.

Supplemental Information
Financial – Quarterly extracted information

(Cdn$ thousands, except per share amounts, production and unit prices)	Q4 2022	Q3 2022	Q2 2022	Q1 2022	Q4 2021	Q3 2021	Q2 2021	Q1 2021
OPERATING								
Production volumes								
Crude oil (bbls/d)	8,958	9,279	10,025	9,874	7,135	5,854	7,317	6,968
Natural gas (Mcf/d)	99,512	111,353	116,667	113,703	101,028	95,304	104,784	109,122
Natural gas liquids (bbls/d)	3,984	4,273	4,397	4,030	3,787	3,014	3,864	4,967
Total (boe/d)	29,527	32,111	33,867	32,854	27,760	24,752	28,645	30,122
Liquids weighting %	44	42	43	42	39	36	39	40
Oil and gas revenue ($/boe)	73.14	69.91	81.09	64.10	54.50	45.25	38.96	35.43
Operating netback ($/boe) [1]	43.96	34.77	41.75	36.22	20.22	13.01	14.19	15.86
Oil and gas sales revenue	198,676	206,518	249,908	189,542	139,183	103,047	101,551	96,062
Operating netback [2]	119,414	102,689	128,673	107,108	51,653	29,617	36,986	43,018
Net cash from operating activities	76,131	95,138	129,623	70,463	33,540	25,492	31,701	29,851
Per common share – basic	0.19	0.24	0.33	0.18	0.09	0.07	0.08	0.08
Per common share – diluted	0.07	0.10	0.13	0.18	0.03	0.07	0.08	0.08
Adjusted funds from operations [3]	108,937	94,226	119,906	100,464	43,528	23,228	30,421	35,953
Per common share – basic [4]	0.28	0.24	0.31	0.26	0.11	0.06	0.08	0.09
Per common share – diluted [4]	0.10	0.10	0.12	0.26	0.05	0.06	0.08	0.09
Net profit (loss)	67,298	67,251	96,993	(6,442)	37,139	(25,319)	(50,016)	(33,625)
Net profit (loss) attributable to ordinary equity holders	60,584	60,782	90,825	(6,442)	31,344	(30,903)	(55,340)	(33,625)
Per common share – basic	0.15	0.15	0.23	(0.02)	0.08	(0.08)	(0.14)	(0.09)
Per common share – diluted	0.06	0.06	0.09	(0.02)	0.03	(0.08)	(0.14)	(0.09)
Net cash used in investing activities	145,556	58,669	68,414	95,514	42,190	20,809	6,731	21,450
Capital expenditures [5]	173,669	77,332	50,387	82,488	68,385	39,606	11,370	19,183
Free funds flow [6]	(64,732)	16,894	69,519	17,853	(24,857)	(16,377)	19,051	16,770
Weighted average common shares outstanding [7]								
Basic	392,556	392,309	391,179	391,148	391,117	391,113	391,113	391,080
Diluted	1,058,515	967,757	975,668	391,148	952,281	391,113	391,113	391,080
FINANCIAL *(as at each quarter end)*								
Adjusted working capital deficit [8]	32,915	37,002	5,180	16,470	52,443	29,596	4,329	130,206
Available funding [9]	309,985	327,898	402,720	206,930	188,957	227,304	243,685	73,395
Net debt [10]	291,647	222,416	215,155	277,549	293,490	251,963	227,401	252,709

1 Operating netback per boe is a non-GAAP measure. Oil and gas revenue per boe is the most directly comparable GAAP measure to operating netback per boe. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

2 Operating netback is a non-GAAP measure. Oil and gas revenue is the most directly comparable GAAP measure to operating netback. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

3 Adjusted funds from operations is a non-GAAP measure. Net cash from operating activities is the most directly comparable GAAP measure to adjusted funds from operations. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

4 Adjusted funds from operations per basic and diluted common share are non-GAAP measures. Net cash from operating activities per basic and diluted share are the most directly comparable GAAP measure to adjusted funds from operations per basic and diluted common share. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

5 Capital expenditures is a non-GAAP measure. Net cash used in investing activities is the most directly comparable GAAP measure to capital expenditures. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

6 Free funds flow is a non-GAAP measures. Net cash from operating activities is the most directly comparable GAAP measure to free funds flow. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

7 Following the transaction referred to in subsection "Business Combination" in this MD&A, the combined entity has 90,927,765 common shares, 28,549,991 warrants, 5,187,659 RSUs, and 664,328 options issued and outstanding as of the date of this report, March 28, 2023.

8 Adjusted working capital deficit is a capital management measure. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

9 Available funding is a non-GAAP measure. Working capital deficit is the most directly comparable GAAP measure to available funding. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

10 Net debt is a non-GAAP measure. The Company's third party debt obligations of the bank debt and the term debt are the most directly comparable GAAP measures for net debt. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

Disclosure Controls and Procedures

Disclosure controls and procedures ("DC&P") seek to ensure that information to be disclosed by Hammerhead is accumulated and communicated to management, as appropriate, to allow timely decisions regarding required disclosures. As at December 31, 2022, the Chief Executive Officer and the Chief Financial Officer evaluated the effectiveness of the design and operation of the Company's DC&P. Based on their evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's DC&P were effective as at December 31, 2022. All control systems by their nature can only provide reasonable, but not absolute, assurance that the objectives of the control system are met.

Internal Control over Financial Reporting and Officer Certifications

Internal control over financial reporting is a process designed to provide reasonable assurance that all the assets are safeguarded and transactions are appropriately authorized, and to facilitate the preparation of relevant, reliable and timely information. Due to inherent limitations, internal control over financial reporting may not prevent or detect all misstatements due to fraud or error. The control framework Hammerhead's officers used to design and evaluate the Company's internal controls over financial reporting is the Internal Control – Integrated Framework (2013) by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). All control systems by their nature can only provide reasonable, but not absolute, assurance that the objectives of the control system are met.

Significant Estimates

Hammerhead's significant accounting policies are disclosed in note 2 of the 2022 Financial Statements. The preparation of the 2022 Financial Statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, revenues and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future years affected.

Information about significant areas of estimation uncertainty and critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in the Financial Statements are as follows:

(i) Reserves

Reserves engineering is an inherently complex and subjective process of estimating underground accumulations of petroleum and natural gas. The process relies on interpretations of available geological, geophysical, engineering, economic and production data. The accuracy of a reserves estimate is a function of the quality and quantity of available data, the interpretation of that data, the accuracy of various economic assumptions and the judgement of those preparing the estimate. Because these estimates depend on many assumptions, all of which may differ from actual results, reserves estimates and estimates of future net revenue may be different from the sales volumes ultimately recovered and net revenues actually realized. Changes in market conditions, regulatory matters and the results of subsequent drilling, testing and production may require revisions to the original estimates. Estimates of reserves impact: (i) the assessment of whether or not a new well has found economically recoverable reserves; (ii) depletion rates; (iii) the determination of net recoverable amount of oil and gas properties for impairment assessment and measurement, and (iv) the determination of reserve lives which affect the timing of decommissioning activities, all of which could have a material impact on earnings and financial positions. HHR's reserves have been evaluated at December 31, 2022 and 2021 by independent third-party professional engineers, who work with information provided by the Company to evaluate reserves in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101").

(ii) Property, plant and equipment

HHR's oil and gas assets are grouped into a cash generating unit ("CGU"). A CGU is the lowest level of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs require significant judgement and interpretation with respect to the integration between assets, geological formation, geographical proximity, the existence of common sales points and shared infrastructures, product type, similar exposure to market risk and the way in which management monitors its operations. The recoverability of HHR’s oil and gas assets is assessed at the CGU level, and therefore, the determination of a CGU's costs could have a significant impact on impairment losses or impairment reversals.

Judgements are required to assess when impairment indicators are evident and impairment testing is required. The Company monitors internal and external indicators of impairment relating to its tangible assets. The recoverable amounts of the Company’s CGU is determined based on the higher of the present value of value-in-use calculations and fair value less costs of disposal. Recoverable amounts calculated for impairment testing are based on estimates of future commodity prices, expected volumes, quantity of reserves and discount rates as well as future development costs, royalties and operating costs. These calculations require the use of estimates and assumptions, which by their nature, are subject to measurement uncertainty. In addition, judgement is exercised by management as to whether there have been indicators of impairment or of impairment reversal. Indicators of impairment or impairment reversal may include, but are not limited to a change in: the market value of assets, asset performance, estimates of future prices, royalties and costs, estimated quantity of reserves and appropriate discount rates.

(iii) Depletion

Oil and natural gas development and production assets are depleted on a unit-of-production basis at a rate calculated by reference to proved plus probable reserves determined in accordance with NI 51-101 and incorporate the estimated future cost of developing and extracting those reserves.

(iv) Provisions for decommissioning liability costs

Amounts recorded for decommissioning liabilities and the related accretion expense require the use of estimates with respect to the amount and timing of decommissioning expenditures, inflation rates and interest rates. Actual costs and cash outflows can differ from estimates because of changes in law and regulations, public expectations, market conditions, discovery and analysis of site conditions and changes in technology. Decommissioning liabilities are recognized in the period when it becomes probable that there will be a future cash outflow.

(v) Leases

Management applies judgement in reviewing each of its contractual arrangements to determine whether the arrangement contains a lease within the scope of IFRS 16. Leases that are recognized are subject to further management judgement and estimation in various areas specific to the arrangement.

Where a contract is identified as containing a lease, the Company recognizes a right-of-use asset and a corresponding lease obligation on the statement of financial position, as of the date the asset becomes available for use.

The right-of-use assets is measured at cost, comprised of; the initial measurement of the lease liability; the lease payments made at or before the commencement date, net of lease incentives received; the direct costs incurred; and an estimate of the costs to be incurred in restoring the underlying asset to the condition required by the terms of the lease.

The lease liability is measured as the present value of the future lease payments, including; fixed payments, net of incentives received; variable lease payments that depend on an index or a rate; amounts expected to be payable under residual value guarantees, the exercise price of a purchase option if there is reasonable certainty the option will be exercised; and payments of penalties for terminating the lease, if the lease term reflects exercising the option to terminate.

After initial recognition, the right-of-use asset is amortized over the shorter of the useful life of the asset and the lease term, with the depreciation expense recognized in the statement of profit (loss). The carrying amount of the lease liability is increased to reflect interest on the lease and reduced to reflect the lease payments made.

Amendments to the lease could result in a reassessment or modification of the lease liability and the corresponding right-of-use asset. Such amendments may include, but are not limited to, a change in the lease term, a change in the assessment of an option to purchase the underlying asset, a change in the amounts expected to be payable under a residual value guarantee, a change in future lease payments resulting from a change in an index or a rate used to determine those payments, a change in the scope of the lease resulting from the addition or removal of the right to use one or more underlying assets, and a change in the consideration for the lease.

The Company determines the lease term as the non-cancellable term of the lease, together with any periods covered by an option to extend the lease if it is reasonably certain to be exercised, or any periods covered by an option to terminate the lease if it is reasonably certain not to be exercised. The Company applies judgement in evaluating whether it is reasonably certain to exercise the option to renew by considering all relevant factors that create an economic incentive for it to exercise the renewal. After the commencement date, the Company reassesses the lease term if there is a significant event or change in circumstances that is within its control and affects its ability to exercise (or not to exercise) the option to renew (e.g., a change in business strategy).

Where the rate implicit in a lease is not readily determinable, the discount rate of lease obligations is estimated using a discount rate similar to HHR's company-specific incremental borrowing rate. This rate represents the rate that HHR would incur to obtain the funds necessary to purchase an asset of a similar value, with similar payment terms and security in a similar economic environment.

(vi) Share-based compensation

Compensation costs recorded pursuant to share-based compensation plans are subject to the estimated fair values of the awards on the grant date and the estimated number of units that will ultimately vest. The Company uses the Black-Scholes option valuation model to estimate the fair value of options, which requires the Company to determine the most appropriate inputs including the expected life of the options, volatility, forfeiture rates, risk free interest rates and future dividends, which by nature are subject to measurement uncertainty.

(vii) Tax asset valuation and utilization

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company operates are subject to change. The Company is also subject to income tax audits and reassessments which may change its provision for income taxes. Therefore, the determination of income taxes is by nature complex and requires making certain estimates and assumptions. HHR recognizes net deferred tax benefits related to deferred tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of deferred tax assets requires the Company to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in each jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Company to realize the net deferred tax assets recorded at the reporting date could be impacted.

(viii) Fair value determination

The determination of fair value requires judgement and is based on market information, where available and appropriate. Fair value is best evidenced by an independent quoted market price for the same asset or liability in an active market. However, quoted market prices and active markets do not always exist. In those instances, fair valuation techniques are used. The Company applies judgement in determining the most appropriate inputs and the weighting ascribed to each such input as well as its selection of valuation methodologies. The calculation of fair value is based on market conditions as at each reporting date and may not be reflective of ultimate realizable value.

(ix) Risk management contracts

Derivative risk management contracts are valued using valuation techniques with market observable inputs. The most frequently applied valuation techniques include Black-Scholes option valuation model and forward pricing and swap models. The models incorporate various inputs including the credit quality of counterparties, foreign exchange spot and forward rates, volatilities of commodity prices and forward rate curves of the underlying commodity. Changes in any of these assumptions would impact fair value of the risk management contracts and as a result, future net profit (loss) and other comprehensive profit (loss).

(x) Warrant liability

The estimated fair value of the warrant liability depends on judgements regarding several key assumptions including volatility, projected and current share price, risk free rate, as well as likelihood and timing of a future liquidity event, among other considerations. Fluctuations in any of these assumptions could result in material differences in the warrant valuation.

(xi) Contingencies

By their nature, contingencies will only be resolved when one or more future events occur or fail to occur. The assessment of contingencies inherently involves the exercise of significant judgement and estimates of the outcome of future events, including estimates and amounts of future cash flows.

(xii) Capitalized general and administrative costs

The Company capitalizes general and administrative costs that are directly related to bringing an asset to a position in which it can be used to generate future economic benefits. Amounts recorded as capitalized general and administrative costs require the use of estimates and judgements and are, by nature, subject to measurement uncertainty.

Forward-Looking Statements

Certain statements contained in this MD&A constitute forward-looking statements or information (collectively "forward-looking statements") within the meaning of applicable securities legislation, including, but not limited to, management's assessment of future plans, operations and strategies including the focus of the Company's operations; the Company's strategy and objectives for its business and assets; the Company's risk management program and the benefits to be derived therefrom; terms of the Company's risk management contracts; terms of the Company's credit facilities; the Company's CCS program, the anticipated timing thereof and the anticipated benefits therefrom; the anticipated number of wells to be drilled in respect of the 2023 capital program; production and cash flow expectations for 2023; anticipated infrastructure expansions in North and South Karr and the anticipated benefits; production capability in respect of in-field infrastructure; benefits to be derived from the in field infrastructure in 2022 and 2023; anticipated free funds flow; anticipated production in the next three years and the benefits to be derived therefrom; the Company's 2023 annual guidance and underlying assumptions; anticipated production growth in 2023; expectation to retire term debt outstanding; key milestones of the CCS program; the Company's objectives for managing capital, including the Company's short-term capital management objective; expected sources of funding for future capital expenditures; current commitments and working capital deficit; determination of the Company’s depletion and depreciation rates; the Company's contractual obligations; and other matters related to the foregoing. Forward-looking statements are typically identified by words such as "estimate", "anticipate", "expect", "may", "will", "project", "could", "plan", "intend", "should", "potential" and similar words suggesting future events or future performance or may be identified by reference to a future date.

With respect to forward-looking statements contained in this document, the Company has made assumptions regarding, among other things: availability of future acquisition opportunities; future capital expenditure levels; future oil and natural gas prices; future oil and natural gas production levels; future exchange rates and interest rates; ability to obtain equipment and services in a timely manner to carry out development activities; pipeline capacity; the impact of increasing competition; the ability to obtain financing on acceptable terms; the general stability of the economic and political environments in which the Company operates; the timely receipt of any required regulatory approvals; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; that the Company will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; that the Company's conduct and results of operations will be consistent with its expectations; that the Company will have the ability to develop its oil and gas properties in the manner currently contemplated; the ability of the CCS program to drive a reduction in Scope 1 and Scope 2 emissions of the Company; that the Company's oil batteries will be converted to CCS; the board approval of the CCS pilot program; the estimates of the Company's reserves volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects; future accounting standards to be adopted or amended and the expected impact on the Company; that the Company will have the ability to add production and reserves through development and exploitation activities; the impact (and duration thereof) that the COVID-19 pandemic will have on: (i) the demand for crude oil, NGL and natural gas; (ii) the supply chain, including the Company's ability to obtain the equipment and services it requires; and (iii) the Company's ability to produce, transport and/or sell its crude oil, NGL and natural gas; the risk that the Company may not be able to fund its capital expenditures using primarily funds from operations; and the risk that the Company may not maintain a flexible capital structure or sufficient liquidity to meet its financial obligations and to execute its business plans. Although the Company believes that the expectations reflected in the forward-looking statements contained in this document, and the assumptions on which such forward-looking statements are made, are reasonable, readers are cautioned not to place undue reliance on forward-looking statements included in this document, as there can be no assurance that the plans, intentions or expectations upon which the forward-looking statements are based will occur. Readers are cautioned that the foregoing list is not exhaustive of all assumptions which have been considered.

By their nature, forward-looking statements involve numerous known and unknown risks and uncertainties, which may cause the Company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things, the ability of management to execute its business plan; general economic and business conditions; that the Company may not receive all necessary approvals to complete the business combination; the risks of the oil and natural gas industry, such as operational risks in exploring for, developing and producing crude oil and natural gas and market demand; the possibility that government policies or laws may change or governmental approvals may be delayed or withheld; actions by governmental or regulatory authorities including production curtailment and increasing taxes and changing royalty regimes and other incentive programs relating to the oil and gas industry; access to pipeline capacity; unexpected downtime; risks and uncertainties involving geology of oil and natural gas deposits; unexpected drilling results; delays in anticipated timing of drilling and completion of wells; risks and uncertainties regarding the Company's CCS program and the approval and success thereof; the Company's ability to enter into or renew leases; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of estimates and projections relating to production (including decline rates), reserves, costs and expenses; the effect of the COVID-19 pandemic on the Company’s business, operations and financial condition; potential disruption of the Company's operations as a result of the COVID-19 pandemic through potential loss of manpower and labour pools resulting from, among other things, quarantines in the Company's operating areas; fluctuations in oil and natural gas prices, foreign currency exchange rates and interest rates; health, safety and environmental risks; risks associated with unexpected potential future law suits and regulatory actions against the Company; uncertainties as to the availability and cost of financing; inability to extend the Company's credit facility at each review on the current terms, on newly negotiated terms or at all; inability to access sufficient capital from internal and external sources; and the risks described under "Operational and Other Risk Factors" herein. Readers are cautioned that the foregoing list is not exhaustive of all possible risks and uncertainties.

The forward-looking statements contained in this document speak only as of the date of this document. Except as expressly required by applicable securities laws, the Company does not undertake any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this document are expressly qualified by this cautionary statement.

This document contains information that may be considered a financial outlook under applicable securities laws about the Company's potential financial position, including, but not limited to: infrastructure expansions; free funds flow generation in Q4 2023; 2023 expenses and the underlying assumptions; and capital expenditures with respect to the Company's CCS program; all of which are subject to numerous assumptions, risk factors, limitations and qualifications, including those set forth in the above paragraphs. The actual results of operations of the Company and the resulting financial results will vary from the amounts set forth in this document and such variations may be material. This information has been provided for illustration only and with respect to future periods are based on budgets and forecasts that are speculative and are subject to a variety of contingencies and may not be appropriate for other purposes. Accordingly, these estimates are not to be relied upon as indicative of future results. Except as required by applicable securities laws, the Company undertakes no obligation to update such financial outlook. The financial outlook contained in this document was made as of the date of this document and was provided for the purpose of providing further information about the Company's potential future business operations. Readers are cautioned that the financial outlook contained in this document is not conclusive and is subject to change.

Operational and Other Risk Factors

Hammerhead’s operations are conducted in the same business environment as most other Canadian oil and gas operators and the business risks are very similar. The business of exploring for, developing and producing oil and natural gas reserves is inherently risky. The risks set out below are not an exhaustive list, nor should they be taken as a complete summary or description of all the risks related to Company's business and operations. HHR's management team conducts focused strategic planning and has identified the following key risks associated with the Company's business and the oil and natural gas business generally:

- The Company is exposed to commodity price risk whereby the fair value of future cash flows will fluctuate as a result of changes in commodity prices. From time to time, the Company may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Company engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Company's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which: production falls short of the hedged volumes or prices fall significantly lower than projected, there is a widening of price-base differentials between delivery points for production and the delivery point assumed in the hedge arrangement, counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements, or a sudden unexpected event materially impacts oil and natural gas prices.

- The Company's operating costs could escalate and become uncompetitive due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention through stimulus spending or additional regulations, which could have a material adverse effect on its financial performance and cash flows. The cost or availability of oil and gas field equipment may adversely affect the Company's ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services, major equipment items for infrastructure projects and construction materials generally. These materials and services may not be available when required at reasonable prices. A failure to secure the services and equipment necessary to the Company's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Company's financial performance and cash flows.

For additional information relating to Hammerhead's operational and other risk factors, please refer to the Company's December 31, 2022 20-F, which along with other relevant documents, is available on EDGAR at www.sec.gov/edgar and SEDAR at www.sedar.com.

Other Advisories

Oil and Gas

"BOEs" may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

This MD&A contains certain oil and gas metrics, including operating netback, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to the performance in previous periods and therefore such metrics should not be unduly relied upon. Management uses these oil and gas metrics for its own performance measurements and to provide security holders with measures to compare the Company's operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this MD&A, should not be relied upon for investment or other purposes.

The Company’s annual aggregate production for 2022 and 2021, the aggregate production for the past eight quarters and the references to “natural gas”, “crude oil" and "NGLs”, reported in this MD&A consist of the following product types, as defined in NI 51-101 and using a conversion ratio of 6 mcf : 1 bbl where applicable:

	YE 2022	Q4 2022	Q3 2022	Q2 2022	Q1 2022	YE 2021	Q4 2021	Q3 2021	Q2 2021	Q1 2021
Tight oil (bbls/d)	9,531	8,958	9,279	10,025	9,874	6,816	7,135	5,854	7,317	6,968
Shale gas (Mcf/d)	110,273	99,512	111,353	116,667	113,703	102,516	101,028	95,304	104,784	109,122
Natural gas liquids (bbls/d)	4,171	3,984	4,273	4,397	4,030	3,903	3,787	3,014	3,864	4,967
Total (boe/d)	32,081	29,527	32,111	33,867	32,854	27,805	27,760	24,752	28,645	30,122

Non-GAAP and Other Specified Financial Measures

This MD&A includes certain meaningful performance measures commonly used in the oil and natural gas industry that are not defined under IFRS, as outlined below. These performance measures should not be considered in isolation or as a substitute for performance measures prepared in accordance with IFRS and should be read in conjunction with the consolidated financial statements. Readers are cautioned that these non-GAAP and capital management measures are not standardized financial measures under IFRS, and might not be comparable to similar financial measures disclosed by other entities. The non-GAAP and capital management measures used in this report are summarized as follows:

Non-GAAP Financial Measures

Capital Expenditures

Management uses capital expenditures to determine the amount of cash flow used for capital reinvestment and compare its capital expenditures to budget. The measure is comprised of additions to property, plant and equipment ("PP&E") per the consolidated statements of cash flows. See the following table for the reconciliation of capital expenditures to net cash used in investing activities, the most directly comparable GAAP measure.

	Three Months Ended December 31,		Year Ended December 31,		
(Cdn$ thousands)	**2022**	2021	**2022**	2021	2020
Net cash used in investing activities	**145,556**	42,190	**368,153**	91,180	113,328
Proceeds from asset disposition	**—**	—	**—**	10,027	—
Net change in accounts payable related to the addition of PP&E	**28,113**	26,195	**15,723**	37,337	(18,966)
Capital expenditures	**173,669**	68,385	**383,876**	138,544	94,362

Available Funding

The available funding measure allows management and other users to evaluate the Company's short term liquidity, and its capital resources available at a point in time. Available funding is comprised of adjusted working capital, the undrawn component of Hammerhead's Credit Facilities, plus the remaining equity commitment related to any outstanding investment agreements. HHR's available funding is disclosed in the "Liquidity" section within this MD&A, which reconciles to the capital management measure, adjusted working capital and its related balance sheet line items.

Operating Netback

Operating netback is calculated by deducting royalties, operating expense, transportation expense, and realized (losses) gains from risk management contracts from oil and gas revenue. Management believes that operating netback is a key industry performance indicator to assess the profitability of the Company's developed and producing assets, and to provide investors with information that is also commonly presented by peers within the industry. HHR's netback is disclosed in the "Operating Netback" section within this MD&A, which includes its most directly comparable GAAP measure, oil and gas revenue.

Funds from Operations, Adjusted Funds from Operations and Free Funds Flow

Funds from operations is comprised of cash provided by operating activities, excluding the impact of changes in non-cash working capital and settlement of decommissioning obligations. Management believes excluding the changes in non-cash working capital provides a meaningful performance measure of the Company's operations on an ongoing basis, as it removes the impact of changes in timing of collections and payments, which are variable. Decommissioning provision costs incurred also vary depending upon the Company's planned capital program and the maturity of operating areas requiring environmental remediation.

Adjusted funds from operations is funds from operations adjusted for other items that are not considered part of the long-term operating performance of the business. Management considers these measures to be key, as they demonstrate the Company's ability to generate the necessary funds to maintain production and fund future growth. Funds from operations and adjusted funds from operations as presented should not be considered an alternative to, or more meaningful than, cash flow from operating activities, net profits or other measures of financial performance calculated in accordance with IFRS.

Free funds flow is an indicator of the efficiency and liquidity of the business, and provides an indication of funds the Company has available for future capital allocation decisions such as the repayment of long-term debt. The measure is calculated as adjusted funds from operations less capital expenditures and settlement of decommissioning obligations.

The following table reconciles funds from operations, adjusted funds from operations and free funds flow to net cash from operating activities, which is the most directly comparable GAAP measure:

	Three Months Ended December 31,		Year Ended December 31,		
(Cdn$ thousands)	**2022**	2021	**2022**	2021	2020
Net cash from operating activities	**76,131**	33,540	**371,355**	121,111	119,686
Changes in non-cash working capital	**29,958**	(3,231)	**38,657**	(6,131)	9,801
Realized foreign exchange loss on debt repayment	**—**	—	**(5,168)**	—	—
Settlement of decommissioning obligations	**—**	—	**123**	—	—
Loss on settlement under long term retention program	**—**	—	**—**	(527)	—
Funds from operations	**106,089**	30,309	**404,967**	114,453	129,487
Optimization fees	**—**	13,665	**—**	19,708	670
Transaction costs	**3,059**	—	**19,080**	—	—
(Gain) loss on foreign exchange	**(944)**	(621)	**7,229**	(350)	817
Unrealized gain (loss) on foreign exchange	**1,112**	630	**(4,804)**	341	(813)
Other income, excluding transportation income	**(379)**	(455)	**(2,939)**	(1,022)	(1,143)
Adjusted funds from operations	**108,937**	43,528	**423,533**	133,130	129,018
Capital expenditures	**(173,669)**	(68,385)	**(383,876)**	(138,544)	(94,362)
Settlement of decommissioning obligations	**—**	—	**(123)**	—	—
Free funds flow	**(64,732)**	(24,857)	**39,534**	(5,414)	34,656

Non-GAAP Financial Ratios

Operating Netback per boe

Management calculates operating netback per boe as operating netback divided by the Company's total production. Operating netback is a non-GAAP financial measure component of operating netback per boe. Management believes this performance measure provides key information about the profitability of the Company's developed and producing assets, isolated for the impact of changes in production volumes. HHR's operating netback per boe is disclosed in the "Operating Netback" section within this MD&A.

Funds from Operations per boe and Funds from Operations per Basic Share and Diluted Share

Funds from operations per boe is calculated by dividing funds from operations by the Company's total production. Funds from operations per basic share and diluted share is calculated by dividing funds from operations by the Company's basic and diluted weighted average shares outstanding. Funds from operations is a non-GAAP financial measure component of funds from operations per boe, and funds from operations per basic share and diluted share.

Funds from operations per boe is utilized by management to assess the profitability of the Company's developed and producing assets and to compare current results to prior periods or to peers by isolating for the impact of changes in production volumes. Funds from operations per basic share and diluted share is utilized by management to indicate the funds generated from the business that could be allocated to each shareholder's equity position. Funds from operations per boe and funds from operations per basic share and diluted share are disclosed in the "Funds from Operations" section within this MD&A.

Adjusted Funds from Operations per boe and Adjusted Funds from Operations per Basic Share and Diluted Share

Adjusted funds from operations per boe is calculated by dividing adjusted funds from operations by the Company's total production. Adjusted funds from operations per basic share and diluted share is calculated by dividing adjusted funds from operations by the Company's basic and diluted weighted average shares outstanding. Adjusted funds from operations is a non-GAAP financial measure component of adjusted funds from operations per boe, and adjusted funds from operations per basic share and diluted share.

Adjusted funds from operations per boe is utilized by management to assess the profitability of the Company's developed and producing assets, adjusted for items that are not considered part of the long-term operating performance of the business, and to compare current results to prior periods or to peers by isolating for the impact of changes in production volumes. Adjusted funds from operations per basic share and diluted share is utilized by management to indicate the funds generated from the business that could be allocated to each shareholder's equity position. Adjusted funds from operations per boe and adjusted funds from operations per basic share and diluted share are disclosed in the "Adjusted Funds from Operations" section within this MD&A.

Capital Management Measures

Adjusted EBITDA and Annualized Quarterly Adjusted EBITDA

Adjusted EBITDA is calculated as net profit (loss) before interest and financing expenses, income taxes, depletion, depreciation and amortization, adjusted for certain non-cash items, or other items that are not considered part of normal business operations. Annualized quarterly adjusted EBITDA is adjusted EBITDA for the quarter, multiplied by four. Adjusted EBITDA indicates the Company's ability to generate funds from its asset base on a continuing and long-term basis, for future development of its capital program and settlement of financial obligations.

Adjusted EBITDA as presented should not be considered an alternative to, or more meaningful than, net profit (loss) before income tax, or other measures of financial performance calculated in accordance with IFRS. The following is a reconciliation of adjusted EBITDA to the most directly comparable GAAP measure, net profit (loss) before income tax:

	Year Ended December 31,		
(Cdn$ thousands)	**2022**	2021	2020
Net profit (loss) before income tax	**256,820**	(71,821)	53,410
Add (deduct):			
Unrealized (gain) loss on risk management contracts	**(38,112)**	16,649	18,353
Optimization fees	**—**	19,708	670
Transaction costs	**19,080**	—	—
Share-based compensation	**10,044**	14,039	7,155
Depletion and depreciation	**147,168**	127,333	135,184
Finance expense	**25,497**	21,264	37,344
Loss (gain) on foreign exchange	**7,229**	(350)	817
Loss (gain) on warrant liability	**10,611**	96	(3,981)
Loss (gain) on debt repayment	**218**	—	(88,160)
Loss on asset disposition	**—**	13,813	—
Loss on settlement under long term retention program	**—**	527	—
Other income, excluding transportation income	**(2,939)**	(1,022)	(4,639)
Adjusted EBITDA	**435,616**	140,236	156,153

Adjusted Working Capital

Previously, working capital was computed including risk management contracts and the current portion of lease obligations. As at December 31, 2022 and 2021, adjusted working capital has been computed excluding these items. The current presentation of adjusted working capital is aligned with measures used by management to monitor its liquidity for use in budgeting and capital management decisions. Adjusted working capital is defined as the sum of cash, accounts receivable, prepaid expenses and deposits and accounts payable and accrued liabilities.

(Cdn$ thousands)	**December 31, 2022**	December 31, 2021
Cash	**(8,833)**	(12,239)
Accounts receivable	**(89,235)**	(49,433)
Prepaid expenses and deposits	**(4,564)**	(2,751)
Accounts payable and accrued liabilities	**135,547**	116,866
Adjusted working capital deficit	**32,915**	52,443

Net Debt, Net Debt to Adjusted EBITDA, and Net Debt to Annualized Quarterly Adjusted EBITDA

Net debt is calculated as the outstanding balance on the Company's bank debt, term debt and adjusted working capital. Term debt (2020 Senior Notes) is calculated as the principal amount outstanding, plus accrued PIK interest, converted to Canadian dollars at the closing exchange rate for the period. Net debt to adjusted EBITDA is net debt divided by adjusted EBITDA. Net debt to annualized quarterly adjusted EBITDA is net debt divided by annualized quarterly adjusted EBITDA. Net debt is used to assess and monitor liquidity at a point in time, while the net debt to EBITDA ratios assist the Company in monitoring its capital structure and financing requirements.

Net debt and net debt to adjusted EBITDA are disclosed in the "Liquidity" section within this MD&A.

Abbreviations

The following is a list of abbreviations that may be used in this MD&A:

bbl	barrel	AECO	AECO "C" hub price index for Alberta natural gas
bbls/d	barrels per day	Crude oil	Tight oil as defined in National Instrument 51-101
boe	barrels of oil equivalent	Natural gas	Shale gas as defined in National Instrument 51-101
boe/d	barrels of oil equivalent per day	GAAP	generally accepted accounting principles
Mcf	thousand cubic feet	G&A	general and administrative
Mcf/d	thousand cubic feet per day	WTI	West Texas Intermediate
MMbbl	million barrel	USD	U.S. dollars
MMmcf	million cubic feet	CAD	Canadian dollars
MMboe	million barrels of oil equivalent	US	United States
mmbtu	million British Thermal Units	CDN	Canadian
NGL	Natural gas liquids	RSUs	Restricted Share Units
GJ	gigajoule		

CORPORATE INFORMATION

BOARD OF DIRECTORS
Bryan Begley[2,3]
Paul Charron[1,2]
Stewart Hanlon[1,3,4]
Michael G. Kohut
James McDermott[1,4]
Jesal Shah
Scott Sobie
Robert Tichio

[1] Member of Audit Committee
[2] Member of Reserves Committee
[3] Member of Compensation Committee
[4] Member of Governance and ESG Committee

EXECUTIVES

Scott Sobie
President & Chief Executive Officer

Michael G. Kohut
Senior Vice President & Chief Financial Officer

Daniel Labelle
Senior Vice President of Development & A&D

David M. Anderson
Senior Vice President of Operations & Alternative Energy

Nicki Stevens
Senior Vice President of Production, Marketing & ESG

Dick Unsworth
Senior Vice President of Business and Organizational Effectiveness

STOCK EXCHANGE LISTINGS
Hammerhead Energy Inc's shares are publicly traded on the TSX and Nasdaq under the symbol HHRS.

Hammerhead Energy Inc's warrants are publicly traded on the TSX and Nasdaq under the symbols HHRS.WT and HHRSW.

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