Hammerhead Resources Inc.

Management's Discussion and Analysis
As at and for the Three Months and Year Ended
December 31, 2021

Dated: March 30, 2022

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 was incorporated pursuant to the provisions of the Business Corporations Act (Alberta) on November 27, 2009 under the name 1504140 Alberta Ltd. It changed its name to Canadian International Oil Corp. ("CIOC") on April 20, 2010. On October 1, 2017, CIOC amalgamated with its wholly owned subsidiary Canadian International Oil Operating Corp. and changed its name to "Hammerhead Resources Inc." On December 15, 2017, the Company dissolved its foreign subsidiary "Canadian International Oil (USA) Corp." On December 31, 2017, the Company dissolved its remaining foreign subsidiaries, "Canadian International Oil (Barbados) Corp." and "Canadian International Oil (Overseas) Corp." On March 11, 2019, the Company incorporated a new 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 is in its preliminary phase with no active operations as at the date of the MD&A.

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

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.

This MD&A contains forward-looking statements and non-IFRS 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-IFRS Measures" included at the end of this MD&A.

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 year ended December 31, 2021. This MD&A is dated March 30, 2022 and should be read in conjunction with the audited consolidated financial statements as at and for the year ended December 31, 2021 (the "2021 Financial Statements").

Refer to the "Other Advisories" section of this MD&A for reconciliations and information regarding the following non-IFRS financial measures used in this MD&A: "operating netback", "adjusted working capital", "available funding", "Adjusted EBITDA", "net debt", "net debt to Adjusted EBITDA", "total capitalization", "funds from operations", "funds from operations per boe", "funds from operations per share" and "funds from operations per diluted share".

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 polices 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

OPERATIONS	Three Months Ended December 31,			Year Ended December 31,		
(Cdn$ thousands, except per share amounts, production and unit prices)	2021	2020	% Change	2021	2020	% Change
Production Volumes						
Crude oil (bbls/d)	7,135	7,177	(1)	6,816	7,798	(13)
Natural gas (Mcf/d)	101,028	114,330	(12)	102,516	111,450	(8)
Natural gas liquids (bbls/d)	3,787	4,192	(10)	3,903	3,658	7
Total (boe/d)	27,760	30,424	(9)	27,805	30,031	(7)
Liquids weighting %	39	37		39	38	
Average Realized Prices						
Crude oil ($/bbl)	92.34	49.91	85	80.03	44.04	82
Natural gas ($/Mcf)	5.88	3.12	88	4.44	2.56	73
Natural gas liquids ($/bbl)	68.60	29.81	130	52.51	25.04	110
Total ($/boe)	54.50	27.59	98	43.34	23.97	81
Operating netback and funds from operations ($/boe)[1]						
Revenue	54.50	27.59	98	43.34	23.97	81
Royalties	(5.68)	(2.40)	137	(3.80)	(1.56)	144
Operating expense	(8.38)	(6.49)	29	(8.15)	(7.05)	16
Net transportation expense	(6.04)	(4.96)	22	(6.09)	(5.18)	18
Operating netback, excluding realized (losses) gains on risk management contracts	34.40	13.74	150	25.30	10.18	149
Realized (losses) gains on risk management contracts	(14.18)	2.23	(736)	(9.40)	6.02	(256)
Operating netback	20.22	15.97	27	15.90	16.20	(2)
G&A expense	(2.60)	(3.04)	(14)	(2.12)	(1.99)	7
Optimization fees	(5.35)	—	100	(1.94)	(0.06)	3,133
Cash interest expense	(0.58)	(1.23)	(53)	(0.65)	(2.47)	(74)
Other income[1]	0.18	0.09	100	0.10	0.10	—
Funds from operations[1]	11.87	11.79	1	11.29	11.78	(4)
Oil and gas sales revenue	139,183	77,210	80	439,843	263,514	67
Funds from operations[1]	30,309	32,986	(8)	114,453	129,487	(12)
Per common share – basic	0.08	0.08		0.29	0.33	
Per common share – diluted	0.03	0.04		0.29	0.17	
Net (loss) profit	37,139	22,600	64	(71,821)	53,410	(234)
Per common share – basic	0.09	0.06		(0.18)	0.14	
Per common share – diluted	0.04	0.03		(0.18)	0.07	
Capital expenditures	68,385	21,558	217	138,544	94,362	47
Weighted average common shares outstanding						
Basic	391,117	391,038	—	391,106	391,052	—
Diluted	1,005,039	896,778	12	391,106	774,335	(49)

FINANCIAL	As at December 31, 2021	2020	% Change
Adjusted working capital deficit[1]	76,528	26,039	194
Available funding[1]	164,872	34,151	383
Net debt[1]	317,575	310,074	2

1. Non-IFRS measure – see below under "Other Advisories - Non-IFRS Measures".

Fourth Quarter 2021 Operating and Financial Highlights:

- Production averaged 27,760 boe/d in the fourth quarter of 2021, a 2,664 boe/d decrease from the same period of 2020, primarily driven by natural well declines and the timing of new wells coming on-stream.

- The Company's liquids weighting increased from 37% to 39% during the fourth quarter of 2021, compared to the corresponding period of 2020. The increase is due to a higher oil to gas ratio from a six gross (six net) well pad brought on-stream in the fourth quarter of 2021, which accounted for nearly 20% of the Company's total production in the period.

- Operating netback was $20.22/boe for the fourth quarter of 2021, reflecting an increase of $4.25/boe from the same period of 2020. Improvements in commodity pricing resulted in an increase in revenue of $26.91/boe, but also contributed to a $16.41/boe increase in realized losses on risk management contracts and a $3.28/boe increase in royalty expense, which partially offset the increase in revenue. Compared to the fourth quarter of 2020, operating expense increased $1.89/boe and transportation expense increased $1.08/boe, further offsetting improvements in revenue.

- Funds from operations were $30.3 million ($0.08 per basic share and $0.03 per diluted share) for the fourth quarter of 2021, a $2.7 million or 8% decrease from the same quarter of 2020. The decrease is primarily due to optimization fees of $13.7 million recognized in the fourth quarter of 2021, partially offset by a $7.0 million increase in operating netback, a decrease in G&A expense of $1.9 million and a reduction in cash interest paid of $2.0 million.

- Net profit totaled $37.1 million in the fourth quarter of 2021 compared to a net profit of $22.6 million in the same period of 2020. The increase was primarily driven by non-cash items, including a $56.1 million increase in unrealized gains on risk management contracts, partially offset by a $31.5 million reduction in gains related to the 2020 Senior Notes (defined herein) debt redemption and a $5.5 million decrease in unrealized gain on foreign exchange.

- Capital expenditures during the fourth quarter of 2021 were $68.4 million. The Company focused its capital activities on the drilling, completion and tie-in of a six gross (six net) well pad in Gold Creek and a three gross (three net) well pad in Karr. The Company also initiated the drilling and pipeline work for a four gross (four net) well pad in Karr, and finished completion and tie-in work for a six gross (six net) well pad in Gold Creek.

2021 Annual Operating and Financial Highlights:

- Production averaged 27,805 boe/d for the year ended December 31, 2021, a 2,226 boe/d decrease from the same period of 2020, primarily driven by natural well declines and the timing of new wells coming on-stream.

- The Company's liquids weighting was 39% during the year ended December 31, 2021, a slight increase from 38% in the corresponding period of 2020. The increase is due to temperature optimizations implemented at a third party gas processing plant, which improved the Company's overall natural gas liquids ("NGL") yield.

- Operating netback was $15.90/boe for the year ended December 31, 2021, reflecting a decrease of $0.30/boe from the same period of 2020. Although improvements in commodity pricing generated $19.37/boe of additional revenue, it also resulted in an increase in realized losses on risk management contracts of $15.42/boe and a $2.24/boe increase in royalty expense, which offset the increase in revenue. Further contributing to the decrease in operating netback were increases in both operating and transportation expense of $1.10/boe and $0.91/boe, respectively.

- Funds from operations were $114.5 million ($0.29 per basic and diluted share) for the year ended December 31, 2021, a $15.0 million or 12% decrease from the same period in 2020. The decrease is primarily due to higher optimization fees of $19.0 million and a $16.7 million decrease in operating netback, partially offset by a reduction in cash interest paid of $20.6 million.

- Net loss totaled $71.8 million for the year ended December 31, 2021 compared to a net profit of $53.4 million in the same period of 2020. The change was primarily driven by non-cash items, including an $88.2 million reduction in gains related to the 2020 Senior Notes (defined herein) debt redemption and a $13.8 million loss on asset disposition.

- Capital expenditures during the year ended December 31, 2021 were $138.5 million. The Company incurred $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. Additionally, the Company incurred $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, as well as the completion and tie-in of a two gross (two net) well pad.

- On February 5, 2021, the Company issued 67.4 million Series IX first preferred shares, under the June Investment Agreement (as defined herein), for cash proceeds of $33.7 million. As at December 31, 2021, $133.7 million had been drawn, with $166.3 million of equity commitment remaining under the agreement.

- On February 5, 2021 the Company issued 2.6 million Series IX first preferred shares, under the December 2020 Investment Agreement (as defined herein), for cash proceeds of $1.3 million. As at December 31, 2021, $5.1 million had been drawn, with $6.4 million of equity commitment remaining under the agreement.

- On May 31, 2021, the Company entered into an amended and restated senior secured credit facilities agreement for an aggregate principal borrowing base of $175.0 million. As at December 31, 2021, the Company had $106.3 million drawn on the credit facility, with a corresponding undrawn credit facility capacity of $68.7 million.

- On June 16, 2021, the Company sold certain non-core assets and select undeveloped lands for total cash proceeds of $10.0 million, recognizing a loss on disposition of $13.8 million.

- The Company exited December 31, 2021 with a working capital deficit of $76.5 million (December 31, 2020 – deficit of $189.6 million, or $26.0 million after adjusting for current portion of bank debt).

Results of Operations

Production

	Three Months Ended December 31,			Year Ended December 31,		
	2021	2020	% Change	2021	2020	% Change
Crude oil and field condensate (bbls/d)	7,135	7,177	(1)	6,816	7,798	(13)
Natural gas (Mcf/d)	101,028	114,330	(12)	102,516	111,450	(8)
Natural gas liquids (bbls/d)	3,787	4,192	(10)	3,903	3,658	7
Total (boe/d)	27,760	30,424	(9)	27,805	30,031	(7)
Liquids weighting %	39	37		39	38	

Average production during the three months and year ended December 31, 2021 was 27,760 boe/d and 27,805 boe/d, respectively. Production decreased 9% and 7% when compared to the three months and year ended December 31, 2020, respectively, due to natural well declines combined with the timing of new wells on-stream. Since December 31, 2020, 16 gross (14.85 net) wells were brought on-stream, approximately 40% of which did not begin producing until partway through the fourth quarter, contributing only two months of full production. By comparison, all new wells in 2020 came on-stream in the first half of the year, contributing more months of production to the quarterly and annual volumes.

The Company's liquids weighting was 39% during the three months ended December 31, 2021, an increase from 37% in the comparative period of 2020. The increase is due to a high oil to gas ratio of a six gross (six net) well pad brought on-stream in the fourth quarter of 2021, accounting for nearly 20% of the Company's total production for the three months ended December 31, 2021.

The Company's liquids weighting was 39% during the year ended December 31, 2021, a slight increase from 38% in the same period of 2020. The increase is due to temperature optimizations implemented at a third party gas processing plant, which improved the Company's overall NGL yield.

Realized Prices and Benchmark Prices

	Three Months Ended December 31,			Year Ended December 31,		
(Per unit amounts)	**2021**	2020	% Change	**2021**	2020	% Change
Average Realized Prices - net of transportation						
Crude oil and field condensate ($/bbl)	**92.34**	49.91	85	**80.03**	44.04	82
Natural gas ($/Mcf)	**5.88**	3.12	88	**4.44**	2.56	73
Natural gas liquids ($/bbl)[1]	**68.60**	29.81	130	**52.51**	25.04	110
Total ($/boe)	**54.50**	27.59	98	**43.34**	23.97	81
Benchmark Prices						
Crude oil						
WTI (Cdn$/bbl)	**97.18**	55.55	75	**85.14**	52.53	62
Edmonton Light Sweet (Cdn$/bbl)	**93.26**	50.25	86	**80.28**	45.33	77
WTI/Edmonton Light Sweet (Cdn$/bbl)	**(3.92)**	(5.30)	(26)	**(4.87)**	(7.20)	(33)
Natural gas						
AECO 5A (Cdn$/GJ)	**4.41**	2.50	76	**3.43**	2.11	62
AECO 5A (Cdn$/mcf)[2]	**4.70**	2.66	77	**3.66**	2.25	62
NYMEX (US$/MMBtu)	**5.83**	2.66	119	**3.85**	2.08	85
NYMEX (Cdn$/mcf)[2]	**7.41**	3.49	112	**4.87**	2.80	73
Union-Dawn (US$/MMBtu)	**4.65**	2.25	107	**3.61**	1.87	93
Union-Dawn (Cdn$/mcf)[2]	**5.90**	2.96	99	**4.57**	2.52	81
Kingsgate (US$/MMBtu)	**4.18**	2.42	73	**3.13**	1.85	69
Kingsgate (Cdn$/mcf)[2]	**5.32**	3.18	67	**3.96**	2.49	58
Chicago City-Gate (US$/MMBtu)	**4.58**	2.31	98	**5.06**	1.88	168
Chicago City-Gate (Cdn$/mcf)[2]	**5.82**	3.03	92	**6.43**	2.54	152
Stanfield (US$/MMBtu)	**5.32**	2.85	87	**3.87**	2.03	91
Stanfield (Cdn$/mcf)[2]	**6.77**	3.74	81	**4.90**	2.73	79
Malin (US$/MMBtu)	**5.36**	2.87	87	**3.94**	2.06	91
Malin (Cdn$/mcf)[2]	**6.82**	3.77	81	**4.99**	2.77	80
Average foreign exchange						
Exchange rate - US$/CDN$	**1.26**	1.30	(3)	**1.25**	1.34	(7)

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, 2021, the Company's realized crude oil and field condensate price increased by $42.43/bbl or 85% and $35.99/bbl or 82%, respectively, compared to the same periods in the prior year. The increase was driven by improvements in crude oil benchmark prices, reflecting a rise in global demand for oil products which outpaced short term growth in global production. Although some uncertainty surrounding the Covid-19 pandemic and its market impact remains, intermittent easing of pandemic related government restrictions throughout 2021 resulted in an increase in the demand for oil products, as economies re-opened to varying degrees. At the same time, industry wide deferral of capital investments and organized production restrictions from OPEC producers throughout 2020 resulted in reduced oil supply, contributing to the rebound in pricing throughout 2021.

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	**2021**	2020	**2021**	2020
Alberta	**40**	48	**41**	52
Eastern Canada	**33**	28	**32**	29
United States	**27**	24	**27**	19

For the three months and year ended December 31, 2021, Hammerhead’s realized natural gas price increased by $2.76/mcf or 88% and $1.88/mcf or 73%, respectively, compared to the same periods in 2020. The AECO 5A benchmark price increased by $2.04/mcf or 77% and $1.40/mcf or 62%, respectively, during the three months and year ended December 31, 2021, compared to the corresponding periods in 2020. The increase in Hammerhead's realized natural gas price exceeded the increase in AECO 5A benchmark pricing based on a larger proportion of the Company's gas sold to ex-Alberta markets, which settled at a premium to AECO 5A in 2021.

AECO 5A benchmark pricing increased significantly in the first and second quarter of 2021 due to increased pipeline capacity which allowed for greater access to downstream gas markets resulting in a stronger connection of AECO pricing to the US gas benchmark. Though AECO 5A pricing remained strong relative to the 2020 pricing, significant maintenance performed on the NGTL system in the third quarter of 2021 caused a slight decline in AECO prices compared with the pricing of the downstream markets.

The remainder of Hammerhead's natural gas production is delivered to the United States and Eastern Canada markets. During the three months and year ended December 31, 2021, the North American markets experienced increases in prices due to a rise in demand from a colder 2020 winter, resulting in concerns about a supply shortage for the 2021 year. Upward pressure on pricing was further fueled with higher demand for liquefied natural gas exports, resulting in a stronger relationship between the North American markets and the higher priced European and Asian markets. Additionally, as world economies initiated re-openings and lifting of the pandemic related restrictions, concerns over energy shortages have increased. As gas demand returns to pre-pandemic requirements and growth patterns, growing concern about storage capability has further influenced price increases.

NGLs

The Company’s plant condensate and product mix of NGLs are currently sold on the Alberta market, but achieve geographical diversification in pricing through Pembina Pipeline's marketing pool. Pembina operates a pool of sales that provide accessibility to the United States, Asia and Eastern Canadian markets, with market weightings adjusted for supply and demand outlook, as well as seasonality.

For the three months and year ended December 31, 2021, Hammerhead’s realized NGL price increased by $38.79/bbl or 130% and $27.47/bbl or 110%, respectively, compared to the same periods in 2020. Increases in NGL realized prices correlated to a higher WTI benchmark and a rise in international demand for North American NGL products. Cold winters experienced both nationally and internationally contributed to the depletion of global inventories, which was further compounded by industry wide reductions in capital investment throughout 2020 as a result of the pandemic. The increase in NGL pricing throughout 2021 reflects this drop in supply, coupled with increased demand as economies recover from the lifting of pandemic-related public health restrictions.

For the three months ended December 31, 2021, NGL production mix yields were generally consistent with the same period of the prior year, with minor differences due to changing gas composition and volumes from new wells on-stream. For the year ended December 31, 2021, NGL production mix was more heavily weighted to pentane & plant condensate with lower proportion of butane and propane yields. This change in yields was primarily due to operational issues at the Company's third party gas processing plant, which resulted in warmer temperatures to reduce liquid recovery and tank levels, throughout a portion of the second and third quarters of 2021.

% weighting of total NGL production	Three Months Ended December 31, 2021	2020	Year Ended December 31, 2021	2020
Pentane & plant condensate	26	25	29	25
Butane	35	34	33	37
Propane	38	40	36	37
Ethane	1	1	2	1

Revenue

	Three Months Ended December 31,			Year Ended December 31,		
(Cdn$ thousands, except per boe)	**2021**	2020	% Change	**2021**	2020	% Change
Crude oil and field condensate	**60,615**	32,957	84	**199,108**	125,711	58
Natural gas	**54,663**	32,759	67	**165,957**	104,267	59
Natural gas liquids	**23,905**	11,494	108	**74,778**	33,536	123
Oil and natural gas revenue	**139,183**	77,210	80	**439,843**	263,514	67
Revenue per $/boe	**54.50**	27.59	98	**43.34**	23.97	81

The Company earned record quarterly revenue of $139.2 million in the three months ended December 31, 2021, representing an increase of $62.0 million or 80% from the comparative period of 2020. The Company also earned record annual revenue of $439.8 million in year ended December 31, 2021, representing an increase of $176.3 million or 67% from the same period of 2020. For both the three months and year ended December 31, 2021, increased revenue is due to higher realized prices across all commodities, partially offset by a decrease in production.

Royalty Expense

	Three Months Ended December 31,			Year Ended December 31,		
(Cdn$ thousands, except per boe)	**2021**	2020	% Change	**2021**	2020	% Change
Royalties	**14,511**	6,705	116	**38,577**	17,185	124
Royalty expense per $/boe	**5.68**	2.40	137	**3.80**	1.56	144
Percentage of revenue %	**10**	9		**9**	7	

Hammerhead pays royalties to the Province of Alberta in respect to 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 July 2022, the Company qualifies for the Crown's Enhanced Hydrocarbon Recovery Program ("EHRP") associated with a pilot waterflood in a portion of the Company's Gold Creek area. The EHRP provides for a flat royalty of 5% on all commodities produced from specific wells impacted by the waterflood program.

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 three months ended December 31, 2021, royalty expenses increased $7.8 million, or $3.28/boe compared to the same period of 2020. On a percentage of revenue basis, royalties increased from 9% in the fourth quarter of 2020 to 10% in the fourth quarter of 2021. During the year ended December 31, 2021, royalty expenses increased $21.4 million, or $2.24/boe, compared to the same period of 2020. On a percentage of revenue basis, royalties increased from 7% during the year ended December 31, 2020 to 9% during the year ended December 31, 2021.

The increase in royalty expense for both the three months and year ended December 31, 2021 is primarily due to higher commodity prices, which resulted in higher average royalty rates across all commodities. Higher commodity pricing also contributed to an earlier return of capital, and therefore fewer wells benefiting from the low initial 5% royalty rate in 2021 compared to 2020, under the MRF incentive program. These impacts were partially offset by higher GCA credits throughout 2021, compared to 2020.

Operating Expense

	Three Months Ended December 31,			Year Ended December 31,		
(Cdn$ thousands, except per boe)	**2021**	2020	% Change	**2021**	2020	% Change
Gas gathering and processing	**8,194**	8,627	(5)	**37,900**	37,532	1
Chemicals and fuel	**3,933**	1,995	97	**11,819**	11,114	6
Repairs and maintenance	**2,499**	1,973	27	**10,187**	8,448	21
Staff and contractor costs	**2,184**	2,554	(14)	**8,200**	9,852	(17)
Well servicing	**610**	212	188	**1,916**	1,206	59
Other	**3,982**	2,813	42	**12,699**	9,325	36
Operating expense	**21,402**	18,174	18	**82,721**	77,477	7
Operating expense per $/boe	**8.38**	6.49	29	**8.15**	7.05	16

For the three months ended December 31, 2021, operating expense increased $3.2 million or $1.89/boe, compared to the corresponding period of 2020. The increase in costs is primarily due to an increase in chemicals and fuel, higher Other operating costs and higher repairs and maintenance.

Higher chemicals and fuel expense is primarily due to higher gas sweetening and water treating chemical consumption, as well as increased unit prices which came into effect in the fourth quarter of 2021. The increase in Other operating costs is partly due to higher carbon tax expense, resulting from a change in rates under the Government TIER program. The Company also incurred higher regulator charges with the return to normal levies in 2021, after an industry wide exemption was granted in 2020 to alleviate Covid 19 impacts. The rise in repair and maintenance charges was primarily related to continuation of work from the third quarter related to compressor overhauls at two Gold Creek batteries and a plant turnaround in Karr.

For the year ended December 31, 2021, operating expense increased $5.2 million or $1.10/boe when compared to the corresponding period of 2020. The increase was primarily due to higher Other operating expense and increased repairs and maintenance charges. Higher well servicing costs, chemicals and fuel, and gas gathering and processing fees were almost entirely offset with decreases in staff and contractor costs.

Other operating expense increased primarily as the result of a one time favorable accrual adjustment recognized in the first half of 2020, higher federal carbon tax expense, higher environmental remediation activities and increased regulator levies. Repairs and maintenance costs increased as the result of the plant turnaround and compressor overhauls completed in the third and fourth quarters of 2021. Well servicing increases primarily relate to a higher number of workover and wireline activities performed in 2021 compared to 2020. Higher chemicals and fuel is primarily due to increases in global pricing which came into effect in the fourth quarter of 2021, and more than offset slight decreases in chemical consumption for the year overall. Gas gathering and processing increased due to higher take-or-pay charges under firm service agreements, as a result of increased firm volume commitments effective May 2021 coupled with lower gas volumes produced. Decreases in staff and contractor costs were a result of efficiency initiatives including negotiated rate reductions with third-party vendors.

Transportation Expense

	Three Months Ended December 31,			Year Ended December 31,		
(Cdn$ thousands, except per boe)	**2021**	2020	% Change	**2021**	2020	% Change
Transportation expense - gross	**15,421**	13,966	10	**62,044**	57,393	8
Transportation income	**(12)**	(84)	(86)	**(180)**	(411)	(56)
Net transportation expense	**15,409**	13,882	11	**61,864**	56,982	9
(Per boe)						
Transportation expense - gross	**6.04**	4.99	21	**6.11**	5.22	17
Transportation income	**—**	(0.03)	(100)	**(0.02)**	(0.04)	(50)
Net transportation expense	**6.04**	4.96	22	**6.09**	5.18	18

During the three months ended December 31, 2021, gross transportation expense was $15.4 million or $6.04/boe, an increase of $1.5 million or $1.05/boe from the corresponding period of 2020. For the year ended December 31, 2021, gross transportation expense was $62.0 million or $6.11/boe, an increase of $4.7 million or $0.89/boe compared to the same period of 2020. For both the three months and year ended December 31, 2021, the increase in gross transportation expense is largely due to higher gas and NGL transportation charges. An increase in committed firm service gas volumes effective April 2021, coupled with a small decline in gas volumes produced, resulted in higher take-or-pay charges in 2021. Further contributing to higher gas transportation charges was a higher proportion of gas volumes sold to ex-Alberta markets, which typically earn a premium to Alberta market prices but also have higher transportation fees. Higher NGL transportation expense was due to increased trucking and longer terminal wait times, as competitor activity resumed to normal levels following pandemic related shut ins throughout 2020.

Risk Management Contracts

The Company continues to execute a consistent risk management program which is primarily designed to reduce revenue and cash flow volatility, help ensure there are sufficient cash flows to service debt obligations and fund a portion of 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 and the underlying commodity reference prices.

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

(Cdn$ thousands)	**December 31, 2021**	December 31, 2020
Oil liability	**(13,463)**	(11,954)
NGL liability	**(9,869)**	—
Gas (liability) asset	**(2,773)**	2,497
Net fair value liability	**(26,105)**	(9,457)

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

	Three Months Ended December 31,			Year Ended December 31,		
(Cdn$ thousands, except per boe)	**2021**	2020	% Change	**2021**	2020	% Change
Realized (loss) gain on risk management contracts[1]	**(36,208)**	6,234	(681)	**(95,407)**	66,121	(244)
Unrealized gain (loss) on risk management contracts[2]	**46,238**	(9,836)	(570)	**(16,649)**	(18,353)	(9)
Total gain (loss) on risk management contracts	**10,030**	(3,602)	(378)	**(112,056)**	47,768	(335)

(Per boe)						
Realized (loss) gain on risk management contracts[1]	**(14.18)**	2.23	(736)	**(9.40)**	6.02	(256)
Unrealized gain (loss) on risk management contracts[2]	**18.10**	(3.51)	(615)	**(1.64)**	(1.67)	(2)
Total gain (loss) on risk management contracts	**3.92**	(1.29)	(405)	**(11.04)**	4.35	(354)

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 and year ended December 31, 2021, the Company incurred realized losses on risk management contracts of $36.2 million and $95.4 million, respectively, compared to realized gains of $6.2 million and $66.1 million, respectively, during the comparative periods in 2020. The year-over-year change relates to improvements in strip pricing across all commodities relative to the underlying prices of the risk management contracts, with the largest impact incurred on settlement of the Company's oil contracts.

The unrealized gain on risk management contracts of $46.2 million for the three months ended December 31, 2021 is primarily due to settlement of out-of-the money contracts throughout the quarter, as well as mild deterioration of Dawn strip pricing at December 31, 2021, relative to September 30, 2021.

The unrealized loss on risk management contracts of $9.8 million for the three months ended December 31, 2020 is primarily due to settlement of in-the-money crude oil contracts throughout the quarter, as well as improvements in Crude oil strip pricing at December 31, 2020, relative to September 30, 2020. These impacts were partially offset by deterioration of AECO strip relative to the underlying prices of the risk management contracts, thereby moving outstanding AECO contracts from a liability position at September 30, 2020 to an asset position at December 31, 2020.

The unrealized loss on risk management contracts of $16.6 million for the year ended December 31, 2021 is due to improvements in strip pricing across all commodities at December 31, 2021, relative to the underlying prices of the risk management contracts. The unrealized loss on risk management contracts of $18.4 million for the year ended December 31, 2020 is primarily related to improvements in crude oil strip pricing at December 31, 2020 relative to the underlying prices of the risk management contracts, as well as settlement of in-the-money contracts throughout the year.

As at December 31, 2021, 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, 2022 – Dec 31, 2022	CDN$ WTI	1,000	72.95
Jan 1, 2022 – Jun 30, 2022	US$ WTI	1,000	75.15
Jan 1, 2022 – Dec 31, 2022	US$ WTI	2,600	66.94
Jan 1, 2023 – Dec 31, 2023	US$ WTI	1,100	65.00
NGL Swaps			
Jan 1, 2022 – Dec 31, 2022	CDN$ OPIS	1,000	27.50

Remaining Term	Reference	Total Daily Volume (MMbtu/d)	Weighted Average (US$/MMbtu)
Natural Gas Swaps			
Jan 1, 2022 - Dec 31, 2022	US$ Dawn	30,000	3.50
Jan 1, 2023 - June 30, 2023	US$ Dawn	30,000	3.04

Operating Netback

	Three Months Ended December 31,			Year Ended December 31,		
(Cdn$ thousands, except per boe and per share)	**2021**	2020	% Change	**2021**	2020	% Change
Revenue	**139,183**	77,210	80	**439,843**	263,514	67
Royalties	**(14,511)**	(6,705)	116	**(38,577)**	(17,185)	124
Operating expense	**(21,402)**	(18,174)	18	**(82,721)**	(77,477)	7
Net transportation expense	**(15,409)**	(13,882)	11	**(61,864)**	(56,982)	9
Operating netback, excluding realized (losses) gains on risk management contracts	**87,861**	38,449	129	**256,681**	111,870	129
Realized (losses) gains on risk management contracts	**(36,208)**	6,234	(681)	**(95,407)**	66,121	(244)
Operating netback	**51,653**	44,683	16	**161,274**	177,991	(9)

($/boe)						
Revenue	**54.50**	27.59	98	**43.34**	23.97	81
Royalties	**(5.68)**	(2.40)	137	**(3.80)**	(1.56)	144
Operating expense	**(8.38)**	(6.49)	29	**(8.15)**	(7.05)	16
Net transportation expense	**(6.04)**	(4.96)	22	**(6.09)**	(5.18)	18
Operating netback, excluding realized (losses) gains on risk management contracts	**34.40**	13.74	150	**25.30**	10.18	149
Realized (losses) gains on risk management contracts	**(14.18)**	2.23	(736)	**(9.40)**	6.02	(256)
Operating netback	**20.22**	15.97	27	**15.90**	16.20	(2)

For the three months ended December 31, 2021, the Company's operating netback was $20.22/boe, an increase of $4.25/boe from to the corresponding period of 2020. Improvements in commodity pricing resulted in an increase in revenue of $26.91/boe, but also contributed to a $16.41/boe increase in realized losses on risk management contracts and a $3.28/boe increase in royalty expense, which partially offset the increase in revenue. Compared to the fourth quarter of 2020, operating expense increased $1.89/boe and transportation expense increased $1.08/boe, further offsetting improvements in revenue.

For the year ended December 31, 2021, the Company's operating netback was $15.90/boe, a decrease of $0.30/boe from the prior year. Although improvements in commodity pricing generated $19.37/boe of additional revenue, it also resulted in an increase in realized losses on risk management contracts of $15.42/boe and a $2.24/boe increase in royalty expense, which offset the increase in revenue. Further contributing to the decrease in operating netback were increases in both operating and transportation expense of $1.10/boe and $0.91/boe, respectively.

General and Administrative ("G&A") Expense

	Three Months Ended December 31,			Year Ended December 31,		
(Cdn$ thousands, except per boe)	**2021**	2020	% Change	**2021**	2020	% Change
Salaries and benefits	**5,663**	7,322	(23)	**19,370**	16,525	17
Information technology	**574**	545	5	**2,195**	1,958	12
Professional fees[1]	**469**	417	12	**1,467**	3,038	(52)
Insurance	**338**	248	36	**1,059**	844	25
Office rent	**200**	191	5	**751**	736	2
Other[2]	**548**	248	121	**1,418**	1,027	38
Gross G&A expense	**7,792**	8,971	(13)	**26,260**	24,128	9
Capitalized G&A	**(1,151)**	(457)	152	**(4,695)**	(2,290)	105
Net G&A expense	**6,641**	8,514	(22)	**21,565**	21,838	(1)
Net G&A per $/boe	**2.60**	3.04	(14)	**2.12**	1.99	7

1. Professional fees include external audit, legal and reserve evaluation fees and other contract services.
2. During the three months and year ended December 31, 2021, "other" includes environmental, social and governance ("ESG") expenses, general office supplies, travel and communication expenses. During the three months and year ended December 31, 2020, "other" includes general office supplies, travel and communication expenses.

For the three months ended December 31, 2021, gross G&A expense decreased by $1.2 million or 13%, compared to the same period in 2020, primarily due to a $1.7 million or 23% decrease in salaries and benefits. During the fourth quarter of 2020, the Company recognized a one time amendment related to the short term incentive program, contributing to increased salaries and benefits in the period. The change in salaries and benefits was slightly offset by an increase in Other G&A of $0.3 million or 121% due to higher spend on ESG expenses and director fees for the three months ended December 31, 2021.

For the year ended December 31, 2021, gross G&A expense increased by $2.1 million or 9%, compared to the same period in 2020. The increase primarily relates to an increase in salaries and benefits of $2.8 million or 17% and an increase in Other G&A expense of $0.4 million or 38%, partially offset by a decrease in professional fees of $1.6 million or 52%. The increase in salaries and benefits is due to a reduction in government assistance received from the CEWS program, amendments to the Company’s short term incentive program, and the restoration of pre-pandemic wages. The increase in Other G&A expense for the year ended December 31, 2021 primarily relates to ESG spending and director fees. The decrease in professional fees is primarily driven by lower fees incurred during the renegotiation of credit facility amendments in 2021, compared to 2020.

Capitalized G&A expense varies with the composition and compensation levels of technical departments and their time attributed to capital projects. Capitalized G&A expense increased for both the three months and year ended December 31, 2021 as compared to the same periods in 2020, based on higher capital activity in the current year. Capital spending in 2020 was lower as the Company managed it's liquidity in the face of the COVID-19 pandemic.

Optimization Fees

	Three Months Ended December 31,			Year Ended December 31,		
(Cdn$ thousands, except per boe)	**2021**	2020	% Change	**2021**	2020	% Change
Optimization fees	**13,665**	—	100	**19,708**	670	2,841
Optimization fees per $/boe	**5.35**	—	100	**1.94**	0.06	3,133

Optimization fees relate to a business improvement project intended to reduce costs and increase efficiencies throughout the Company. The project was initiated in late 2020 through a third party consulting group, and was completed in the fourth quarter of 2021.

The Company incurred fees of $13.7 million in the fourth quarter of 2021, and $19.7 million for the year ended December 31, 2021. By comparison, the Company did not incur any optimization fees in the fourth quarter of 2020, and incurred fees of $0.7 million for the year ended December 31, 2020. The increase in both periods relates to the timing of consulting services performed, and fees incurred with respect to termination of the service agreement.

Share-based Compensation Expense

	Three Months Ended December 31,			Year Ended December 31,		
(Cdn$ thousands, except per boe)	2021	2020	% Change	2021	2020	% Change
Gross share-based compensation	3,872	3,612	7	18,658	8,352	123
Capitalized share-based compensation	(1,115)	(193)	478	(4,619)	(1,197)	286
Net share-based compensation	2,757	3,419	(19)	14,039	7,155	96
Net share-based compensation per $/boe	1.08	1.22	226	1.38	0.65	112

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 increased by $0.3 million or 7% for the three months ended December 31, 2021, compared to the same period of 2020. The increase principally relates to the annual restricted share units ("RSUs") granted in January of 2021, which had an accelerated vesting period of 15 months. This impact was partially offset by a one time stock option modification expense in the fourth quarter of 2020, due to revaluation of the exercise price to align with changes in the underlying share price. Gross share-based compensation increased by $10.3 million or 123% for the year ended December 31, 2021 compared to the same period of 2020, primarily due to the annual RSUs granted in January of 2021.

Capitalized share-based compensation for the three months and year ended December 31, 2021 increased by $0.9 million or 478% and $3.4 million or 286% respectively. The increase was primarily driven by higher gross share-based compensation in 2021 coupled with increased capital activity in 2021.

Finance Expense

	Three Months Ended December 31,			Year Ended December 31,		
(Cdn$ thousands, except per boe)	2021	2020	% Change	2021	2020	% Change
Senior Notes						
Interest on 2017 Senior Notes	—	—	—	—	9,177	(100)
Interest on 2020 Senior Notes - PIK	3,808	3,649	4	14,660	8,714	68
Total Senior Notes interest	3,808	3,649	4	14,660	17,891	(18)
Interest and fees on bank debt	1,087	2,667	(59)	5,979	16,961	(65)
Interest on EDC facility - letters of credit	359	711	(50)	419	711	(41)
Interest on lease obligation	38	60	(37)	181	286	(37)
Amortization of financing costs (discount and debt issue)	—	—	—	—	1,459	(100)
Accretion – decommissioning liabilities	92	(15)	(713)	25	36	(31)
Total finance expense	5,384	7,072	(24)	21,264	37,344	(43)
Cash interest expense per $/boe	0.58	1.23	(53)	0.65	2.47	(74)
Non-cash interest and accretion expense per $/boe	1.53	1.30	18	1.45	0.93	56
Average principal debt outstanding during the period:						
Term debt - Senior Notes	132,033	125,093	6	125,823	176,294	(29)
Bank debt - credit facility	100,936	182,676	(45)	113,633	244,366	(53)
Total average principal debt outstanding	232,969	307,769	(24)	239,456	420,660	(43)

Finance expense is primarily comprised of interest incurred on the Company’s outstanding Senior Notes (as defined herein) and credit facility borrowings (bank debt).

Senior Notes

On July 10, 2017, the Company issued US$160.0 million unsecured senior notes (the "2017 Senior Notes"), which bore interest at 9% per annum, payable in cash semi-annually. On June 19, 2020 the Company amended its unsecured Senior Note agreement. The holders of the 2017 Senior Notes approved the redemption of US$48.0 million of the principal balance; reducing the principal owing from US$160.0 million to US$112.0 million (the "2020 Senior Notes"). Under the 2020 Senior Notes agreement, the effective interest rate increased from 9% to 12%, with the option of paying interest as cash or as paid-in-kind ("PIK"). The Company has exercised the PIK interest option since the amendment date, and therefore all interest accrued since June 19, 2020 has been added to the principal balance outstanding. On October 10, 2020, the Company was granted an additional debt redemption of US$24.0 million related to the 2020 Senior Notes principal balance; reducing the principal owing (excluding PIK interest) from US$112.0 million to US$88.0 million, with no corresponding change to the effective interest rate.

During the three months ended December 31, 2021, interest expense on the 2020 Senior Notes increased by $0.2 million or 4% compared to the same period of 2020. The increase was due to a higher outstanding principal amount on which the interest is calculated, as a result of accrued PIK interest. During the year ended December 31, 2021, interest expense on the 2020 Senior Notes decreased by $3.2 million or 18% compared to the same period of 2020. The decrease was due to a lower average principal outstanding, resulting from the June and October 2020 debt redemptions.

Bank Debt

During the three months ended December 31, 2021, the Company's interest expense and fees on bank debt decreased by $1.6 million or 59% compared to the same period in 2020. The decrease was due to a lower average outstanding principal amount and a lower effective interest rate under the amended credit facility agreement (defined herein).

Interest expense and fees on bank debt decreased by $11.0 million or 65% for the year ended December 31, 2021, as compared to the same period in 2020. The decrease was due to a lower average outstanding principal amount, a lower effective interest rate under the amended credit facility agreement and lower fees incurred during the renegotiation of the amended credit facility agreement.

(Gain) Loss on Foreign Exchange

	Three Months Ended December 31,			Year Ended December 31,		
(Cdn$ thousands, except per boe)	**2021**	2020	% Change	**2021**	2020	% Change
Realized loss (gain) on foreign exchange	**9**	(7)	(229)	**(9)**	4	(325)
Unrealized (gain) loss on foreign exchange	**(630)**	(6,154)	(90)	**(341)**	813	(142)
(Gain) loss on foreign exchange	**(621)**	(6,161)	(90)	**(350)**	817	(143)

The Company's foreign exchange impacts primarily relate to the 2020 Senior Notes, which are denominated in US dollars and translated into Canadian dollars at the end of each reporting period.

Relative to the US dollar, 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 the 2020 Senior Notes, and a corresponding unrealized foreign exchange gain of $0.6 million during the fourth quarter of 2021. Similarly, the Canadian dollar strengthened from 1.3339 at September 30, 2020 to 1.2732 at December 31, 2020. This resulted in a lower Canadian dollar liability for the 2020 Senior Notes, and a corresponding unrealized foreign exchange gain of $6.2 million during the fourth quarter of 2020.

Relative to the US dollar, the Canadian dollar strengthened slightly from 1.2732 at December 31, 2020 to 1.2678 at December 31, 2021. This resulted in a slightly lower Canadian dollar liability for the 2020 Senior Notes, and a corresponding unrealized foreign exchange gain of $0.3 million for the year ended December 31, 2021.

Relative to the US dollar, the Canadian dollar strengthened from 1.2988 at December 31, 2019 to 1.2732 at December 31, 2020. However, during the year ended December 31, 2020, the Company made two debt redemptions on its 2020 Senior Notes, which required revaluation of the outstanding balance immediately prior to redemption. The first redemption occurred on June 19, 2020, at a weaker FX rate than the previous year-end revaluation, resulting in a loss on revaluation. Although FX rates strengthened as at revaluation prior to the second debt redemption and as at the year-end revaluation on December 31, 2020, it was not sufficient to entirely offset the unrealized loss on revaluation prior to the initial debt redemption. As a result, the Company recognized a net unrealized loss on foreign exchange of $0.8 million for the year ended December 31, 2020.

Depletion, Depreciation and Impairment Expense

	Three Months Ended December 31,			Year Ended December 31,		
(Cdn$ thousands, except per boe)	2021	2020	% Change	2021	2020	% Change
Depletion of developed and producing assets	30,235	34,030	(11)	122,623	132,859	(8)
Depreciation of corporate assets	467	438	7	1,481	1,590	(7)
Depreciation of right-of-use assets	186	182	2	741	735	—
Impairment	2,488	—	100	2,488	—	100
Total depletion, depreciation and impairment expense	33,376	34,650	(4)	127,333	135,184	(6)
Per $/boe	13.07	12.38	6	12.55	12.30	2

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 PP&E is depleted using the unit-of-production method based on the estimated recoverable amount from total proved and probable (2P) reserves. 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.

During the three months and year ended December 31, 2021, depletion, depreciation and impairment expense decreased $1.3 million or 4%, and $7.9 million or 6%, respectively, compared to the same periods of 2020. The decrease for both the three months and year ended December 31, 2021 related to lower depletion of developed and producing assets, due to lower production volumes. This impact was partially offset by a $2.5 million impairment expense in the fourth quarter of 2021 related to a decommissioned pipeline.

Funds from Operations

	Three Months Ended December 31,			Year Ended December 31,		
(Cdn$ thousands, except per boe and per share)	2021	2020	% Change	2021	2020	% Change
Operating netback	51,653	44,683	16	161,274	177,991	(9)
G&A expense	(6,641)	(8,514)	(22)	(21,565)	(21,838)	(1)
Optimization fees	(13,665)	—	100	(19,708)	(670)	2,841
Cash interest expense	(1,484)	(3,438)	(57)	(6,579)	(27,135)	(76)
Realized foreign exchange (loss) gain	(9)	7	(229)	9	(4)	(325)
Other cash impacts[1]	455	248	83	1,022	1,143	(11)
Funds from operations	30,309	32,986	(8)	114,453	129,487	(12)
(per boe)						
Operating netback	20.22	15.97	27	15.90	16.20	(2)
G&A expense	(2.60)	(3.04)	(14)	(2.12)	(1.99)	7
Optimization fees	(5.35)	—	100	(1.94)	(0.06)	3,133
Cash interest expense	(0.58)	(1.23)	(53)	(0.65)	(2.47)	(74)
Other cash impacts[1]	0.18	0.09	100	0.10	0.10	—
Funds from operations	11.87	11.79	1	11.29	11.78	(4)
Weighted average common shares outstanding *(000s)*						
Basic	391,117	391,038	—	391,106	391,052	—
Diluted	1,005,039	896,778	12	391,106	774,335	(49)
Per common share - basic	0.08	0.08		0.29	0.33	
Per common share - diluted	0.03	0.04		0.29	0.17	

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

The Company generated funds from operations of $30.3 million during the fourth quarter of 2021, a $2.7 million or 8% decrease from the same quarter of 2020. The decrease is primarily due to optimization fees of $13.7 million recognized in the fourth quarter of 2021, partially offset by a $7.0 million increase in operating netback, a decrease in G&A expense of $1.9 million and a reduction in cash interest paid of $2.0 million.

Funds from operations were $114.5 million for the year ended December 31, 2021, a $15.0 million or 12% decrease from the same period in 2020. The decrease is primarily due to higher optimization fees of $19.0 million and a $16.7 decrease in operating netback, partially offset by a reduction in cash interest paid of $20.6 million.

Net Profit (Loss)

	Three Months Ended December 31,			Year Ended December 31,		
(Cdn$ thousands, except per share)	**2021**	2020	% Change	**2021**	2020	% Change
Net profit (loss)	**37,139**	22,600	64	**(71,821)**	53,410	(234)
Weighted average common shares outstanding						
Basic	**391,117**	391,038	—	**391,106**	391,052	—
Per common share – basic	**0.09**	0.06		**(0.18)**	0.14	
Diluted	**1,005,039**	896,778	12	**391,106**	774,335	(49)
Per common share – diluted	**0.04**	0.03		**(0.18)**	0.07	

(Cdn$ thousands)	
Net profit, three months ended December 31, 2020	22,600
Decrease from funds from operations	**(2,677)**
Add (deduct) change in non-cash items:	
Increase in unrealized gain on risk management contracts	**56,074**
Decrease in gain on debt redemptions	**(31,514)**
Decrease in unrealized gain on foreign exchange	**(5,524)**
Other	**(1,820)**
Net profit, three months ended December 31, 2021	**37,139**

The Company reported a net profit of $37.1 million for the three months ended December 31, 2021, compared to a net profit of $22.6 million in the same period of 2020. The $14.5 million increase was primarily due to non-cash items, including a $56.1 million increase in unrealized gains on risk management contracts, partially offset by a $31.5 million reduction in gains related to the 2020 Senior Notes debt redemption, and a $5.5 million decrease in unrealized gain on foreign exchange.

(Cdn$ thousands)	
Net profit, year ended December 31, 2020	53,410
Decrease from funds from operations	**(15,034)**
Add (deduct) change in non-cash items:	
Decrease in gain on debt redemptions	**(88,160)**
Loss on asset disposition	**(13,813)**
Decrease in depletion, depreciation and impairment	**7,851**
Increase in share-based compensation	**(6,884)**
Increase in finance expense, non-cash	**(4,476)**
Increase in loss on warrant valuation	**(4,077)**
Decrease in unrealized loss on risk management contracts	**1,704**
Increase in unrealized gain on foreign exchange	**1,154**
Gain on farm-out	**(3,496)**
Net loss, year ended December 31, 2021	**(71,821)**

The Company reported a net loss of $71.8 million for the year ended December 31, 2021, compared to a net profit of $53.4 million in the same period of 2020. The $125.2 million change was primarily due to non-cash items, including an $88.2 million reduction in gains related to the 2020 Senior Notes debt redemption, a $13.8 million loss on asset disposition, a $6.9 million increase in share-based compensation expense, a $4.5 million increase in non-cash finance costs related to the PIK interest on the 2020 Senior Notes, a $4.1 million change in fair value of the warrants and a $3.5 million reduction in gains related to the farm-out transaction. These impacts were partially offset by a $7.9 million decrease in depletion, depreciation and impairment, a $1.7 million decrease in unrealized losses on risk management contracts and a $1.2 million increase in unrealized gain on foreign exchange.

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. The components of the unrecognized deferred tax asset are as follows:

(Cdn$ thousands)	**December 31, 2021**	December 31, 2020
PP&E	**(81,924)**	(78,119)
Decommissioning liability	**6,801**	7,245
Lease liability	**903**	416
Share and debt issue costs	**(980)**	171
Foreign exchange	**(505)**	(910)
Unrealized loss on risk management contracts	**6,004**	2,175
Charitable donations	**160**	145
Non-capital losses	**101,621**	88,958
Deferred income tax asset not recognized	**(32,080)**	(20,081)
Deferred income taxes	**—**	—

The deferred income tax provision differs from the expected amount calculated by applying the Canadian combined federal and provincial income tax rate of 23.00% (December 31, 2020 – 23.99%) as summarized in the following table:

(Cdn$ thousands)	**December 31, 2021**	December 31, 2020
Net (loss) profit before income taxes	**(71,821)**	53,410
Statutory income tax rate	**23.00 %**	23.99 %
	(16,519)	12,813
Increase (decrease) resulting from:		
Share-based compensation	**3,229**	1,716
Warrant revaluation	**22**	(955)
Rate change	**(50)**	(586)
Prior year true-up	**1,377**	(293)
Change in unrecognized tax assets	**12,000**	(13,617)
Other	**(59)**	922
Deferred income tax expense (recovery)	**—**	—

At December 31, 2021, the Company had approximately 441.8 million of non-capital losses which begin to expire after 2034 (December 31, 2020 – 386.8 million). The Company has not recognized a deferred tax asset in relation to these losses because of the uncertainty regarding future taxable profits against which such losses can be offset.

Capital Expenditures

	Three Months Ended December 31, 2021			Year Ended December 31,		
(Cdn$ thousands)	**2021**	2020	% Change	**2021**	2020	% Change
Drilling and completion	**54,305**	13,522	302	**104,051**	63,941	63
Equipment, facilities and pipelines	**9,470**	6,791	39	**22,742**	21,012	8
Workovers and maintenance capital	**3,319**	474	600	**5,851**	5,757	2
Geological & geophysical ("G&G")	**—**	—	—	**1**	45	(98)
Capitalized and other[1]	**1,291**	771	67	**5,899**	3,607	64
Capital expenditures	**68,385**	21,558	217	**138,544**	94,362	47

1. Other includes capitalized salaries and benefits and corporate capital expenditures.

Capital expenditures for the three months and year ended December 31, 2021 were $68.4 million and $138.5 million, respectively.

During 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 the drill, completion and tie-in of a six gross (six net) well pad which came on-stream in January 2022. The remaining funds incurred in Gold Creek were primarily related to finishing the completion and tie-in of a six gross (six net) well pad which came on-stream in October 2021, as well as 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 initiation of drilling and pipeline on another four gross (four net) well pad, as well as construction, workover and maintenance capital.

During 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.

Capital expenditures for the three months and year ended December 31, 2020 were $21.6 million and $94.4 million, respectively. Approximately half of the Company's capital investment related to the drill, completion and tie-in of eight gross (eight net) development wells in the Gold Creek area, all of which came on-stream in June 2020. During the fourth quarter of 2020, the Company incurred $20.3 million to complete and tie-in six gross (six net) development wells in the Gold Creek area, all of which came on-stream in January 2021. Other expenditures during 2020 primarily related to workover and maintenance capital, water disposal facilities in Gold Creek, and development under the farm-out agreement.

Disposition

For the year ended December 31, 2021, proceeds from the disposition of certain non-core assets and undeveloped land were $10.0 million. The Company recognized a loss on disposition in the amount of $13.8 million. The proceeds received from the sale were used to pay down outstanding bank debt.

Net Well Information

	Three Months Ended December 31,		Year Ended December 31,	
(Number of wells)[1]	**2021**	2020	**2021**	2020
Spud	**10**	—	**19**	3.50
Rig released	**10**	—	**17**	5.85
Completed	**14**	6.35	**17.50**	14.70
Wells brought on-stream[2]	**6**	—	**14.85**	12.35

1. Well counts include development Montney and Duvernay wells.
2. Production counts 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, 2021, the Company had 131.0 gross (128.3 net) Montney wells and one gross (one net) Duvernay well capable of producing. This includes six gross (six net) wells that were flowing through test equipment and not yet tied-in to permanent well site facilities. As at December 31, 2020, the Company had 114.0 gross (112.45 net) Montney wells and two gross (two net) Duvernay wells capable of producing.

Land Acreage

	December 31, 2021			December 31, 2020		
	Gross acres	**Net acres**	**Working interest percentage**	Gross acres	Net acres	Working interest percentage
Montney	**126,738**	**113,730**	**90**	192,161	177,428	92
Duvernay	**25,476**	**23,908**	**94**	90,401	89,249	99

In conjunction with the disposition of the Company's non-core assets, Hammerhead disposed of 100% of its working interest in certain undeveloped lands in the Montney (35,541 net acres) and Duvernay (4,800 net acres) areas.

Reserves

The Company's 2021 year-end reserves evaluation was conducted by McDaniel & Associates Consultants Ltd. ("McDaniel") with an effective date of December 31, 2021 (the "McDaniel Report").

The following summarizes certain information contained in the McDaniel Report, which was prepared in accordance with National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities (“NI 51-101”) and the definitions, standards, and procedures contained in the Canadian Oil and Gas Evaluation Handbook (the “COGE Handbook”). McDaniel evaluated 100% of the Company’s reserves. The McDaniel Report is based on forecast prices and costs and applies the McDaniel’s, GLJ's and Sproule's forecast escalated commodity price deck, foreign exchange rate and inflation rate assumptions as at December 31, 2021, as outlined in the table below entitled “average commodity price forecast”. Estimated future net revenue is stated without any provisions for interest costs, other debt service charges or general and administrative expenses, and after the deduction of royalties, operating costs, estimated well abandonment and reclamation costs and estimated future development costs.

Summary of Corporate Reserves[1,2]

The following table is a summary of the Company's estimated reserves at December 31, 2021, as evaluated in the McDaniel Report:

	Oil and Condensate[4] (MMbbl)	Natural Gas Liquids (MMbbl)	Natural Gas[4] (MMcf)	Barrels of Oil Equivalent[3] (MMboe)	% Liquids
Proved					
Developed Producing ("PDP")	11	7	199	51	35
Undeveloped ("PUD")	38	14	386	116	45
Total Proved ("TP")	**49**	**21**	**585**	**167**	**42**
Probable	53	16	441	143	49
Total Proved plus Probable ("TPP")	**102**	**37**	**1,026**	**310**	**45**

1. Reserves are presented on a "company gross" basis, which is defined as Hammerhead's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Company.
2. Based on McDaniel's December 31, 2021 average commodity price forecast and costs. See "average commodity price forecast" below.
3. Oil equivalent amounts have been calculated using a conversion ratio of six thousand cubic feet of natural gas to one barrel of oil. See "Other Advisories – Oil and Gas" below.
4. References in the table above to oil refer to the light and medium crude oil product type, and references to natural gas refer to the conventional natural gas product type.

Proved Developed Producing

Proved developed producing reserves at December 31, 2021 were 51 mmboe, an increase of 10% from 47 mmboe at December 31, 2020, and representing a 141% replacement of 2021 production (December 31, 2020 - 150%). The increase was due to efficient conversion of proved undeveloped reserves.

At December 31, 2021, the net present value of total proved developed producing reserves at a 10% discount rate was $632.6 million, representing a 60% increase from $394.6 million at December 31, 2020. The increase was primarily due to improved commodity price forecasts.

Future development costs associated with proved developed producing reserves at December 31, 2021 were $16.6 million, consistent with the prior year. Finding and development ("F&D") costs associated with proved developed producing reserves were 9.52/boe (December 31, 2020 - $5.57/boe), resulting in a recycle ratio of 2.16 (December 31, 2020 - 2.12).

Total Proved

Total proved reserves at December 31, 2021 were 167 mmboe, an increase of 14% from 146 mboe at December 31, 2020. The increase was primarily due to acceleration of wells from probable to five-year proven time frame.

At December 31, 2021, the net present value of total proved reserves at a 10% discount rate was $1.4 billion, a 87% increase from $749.4 million at December 31, 2020. The increase was primarily due to improved commodity price forecasts and acceleration of some locations from probable to proven reserves.

Future development costs associated with total proved reserves at December 31, 2021 were $1.3 billion, an increase of 18% from $1.1 billion at December 31, 2020. F&D costs associated with total proved reserves were $14.80/boe, resulting in a recycle ratio of 1.4.

Total Proved Plus Probable

Total proved plus probable reserves at December 31, 2021 were 310 mmboe, consistent with the prior year, as new reserve bookings were offset by production in 2021.

At December 31, 2021, the net present value of the total proved plus probable reserves at a 10% discount rate was $2.6 billion, a 63% increase compared to $1.6 billion at December 31, 2020. The increase was primarily due improvements in price forecasts and cost performance.

Future development costs associated with total proved plus probable reserves at December 31, 2021 were 2.4 billion, a decrease of 4% from $2.5 billion at December 31, 2020. The decrease was a result of cost improvements, particularly in the Company's Gold Creek area.

Net Present Value of Future Net Revenue Before Income Taxes Discounted at (%/year)[1,2,3,4]

The following table is a summary of the estimated net present value of future net revenue (before income taxes) associated with the Company's reserves as at December 31, 2021, discounted at the indicated percentage rates per year, as evaluated in the McDaniel Report:

	NPV (Before Income Tax) Discounted at				
(Cdn$ thousands)	**0%**	**5%**	**10%**	**15%**	**20%**
Proved					
Developed Producing ("PDP")	775,745	702,543	632,636	576,219	531,411
Undeveloped ("PUD")	1,536,247	1,095,950	799,616	593,882	446,683
Total Proved ("TP")	**2,311,992**	**1,798,493**	**1,432,252**	**1,170,101**	**978,094**
Probable	2,671,442	1,698,040	1,139,284	801,099	586,505
Total Proved plus Probable ("TPP")	**4,983,434**	**3,496,533**	**2,571,536**	**1,971,200**	**1,564,599**

1. The forecast of commodity prices used in the McDaniel Report can be found at mcdan.com, gljpc.com and sproule.com. Also see "Average Commodity Price Forecast" below.
2. Estimated future net revenues are stated without any provision for interest costs, other debt service charges or general and administrative expenses, and after deduction of royalties, operating costs, estimated well abandonment and reclamation costs and estimated future development costs.
3. Estimated future net revenue, whether discounted or not, does not represent fair market value.
4. Net present values of future net revenue after income taxes are estimated to approximate the before income tax values based on the estimated future revenues, available tax pools and future deductible expenses.

Average Commodity Price Forecast (McDaniel, GLJ and Sproule)[1,2]

The following table summarizes the average commodity price forecast, foreign exchange rate and inflation rate assumptions as at December 31, 2021, as applied in the McDaniel Report, for the next ten years.

Year	**Edm Light** *(C$/bbl)*	**WTI Oil** *(US$/bbl)*	**AECO Gas** *(C$/MMBtu)*	**Henry Hub** *($US/MMBtu)*	**Exchange Rate** *(US$/C$)*
2022	86.82	72.83	3.56	3.85	0.80
2023	80.73	68.78	3.21	3.44	0.80
2024	78.01	66.76	3.05	3.17	0.80
2025	79.57	68.09	3.11	3.24	0.80
2026	81.16	69.45	3.17	3.30	0.80
2027	82.78	70.84	3.23	3.37	0.80
2028	84.44	72.26	3.30	3.44	0.80
2029	86.13	73.70	3.36	3.50	0.80
2030	87.85	75.18	3.43	3.58	0.80
2031	89.61	76.68	3.50	3.65	0.80
2032	91.40	78.21	3.57	3.72	0.80
Thereafter	+2.0% per year	+2.0% per year	+2.0% per year	+2.0% per year	0.80

1. The commodity price forecast, foreign exchange rate and inflation rate assumptions were determined using three independent reserve evaluator's price forecasts: McDaniel & Associates Consultants Ltd., GLJ Petroleum Consultants Ltd. and Sproule Associates Ltd. effective January 1, 2022.
2. Inflation is accounted for at 2.0% per year.

Reconciliation of Company Gross Reserves Based on Forecast Prices and Costs[1]

The following table summarizes the change in total proved plus probable reserves from 2020 to 2021:

	Light/Medium Crude Oil and NGLs (MMbbl)		Conventional Natural Gas (MMmcf)		Combined (MMboe)	
Factors	**TP**	**TPP**	**TP**	**TPP**	**TP**	**TPP**
December 31, 2020	58	135	522	1,047	146	309
Dispositions	—	—	—	(2)	—	(1)
Drilling - extensions and improved recovery	14	6	111	58	32	16
Technical revisions - performance	—	(2)	(32)	(75)	(6)	(14)
Pricing - economic factors	2	4	22	36	5	10
Production	(4)	(4)	(38)	(38)	(10)	(10)
December 31, 2021	**70**	**139**	**585**	**1,026**	**167**	**310**

1. Company gross reserves exclude royalty volumes.

Capital Resources and Liquidity

Capital Resources

Bank Debt

(Cdn$ thousands)	**December 31, 2021**	December 31, 2020
Credit facility	**106,300**	—
Tranche A	—	105,600
Tranche B	—	55,000
Operating	—	3,000
Total bank debt outstanding	**106,300**	163,600
Bank debt due within one year	—	163,600
Bank debt due beyond one year	**106,300**	—

Undrawn bank debt capacity

(Cdn$ thousands)	**December 31, 2021**	December 31, 2020
Borrowing base capacity	**175,000**	125,600
Credit facility	**(106,300)**	—
Tranche A	—	(105,600)
Operating	—	(3,000)
Operating – guaranteed letters of credit	—	(910)
Undrawn bank debt capacity	**68,700**	16,090

On May 31, 2021, the Company amended its existing credit facility. The amended credit facility agreement eliminated the tranche A and tranche B components of the previous facility and extended the maturity date of the bank debt. Under the amended credit facility agreement, the aggregate principal borrowing base was increased to $175.0 million, consisting of a $155.0 million revolving syndicated facility and a $20.0 million operating facility. The amended credit facility agreement has a term date of May 31, 2022 and a maturity date of May 31, 2023, with an option to extend for an additional 364 days at the lenders' discretion.

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

On November 13, 2020, the CAD denominated guaranteed letters of credit were transferred to Export Development Canada ("EDC"). As at December 31, 2021, CAD denominated letters of credit held by EDC totaled $13.8 million (December 31, 2020 -

$14.6 million). On August 17, 2021, the USD denominated letters of credit were transferred to EDC. As at December 31, 2021, the Company's USD denominated guaranteed letters of credit, translated into Canadian dollars and held by EDC, totaled $0.9 million (December 31, 2020 - $0.9 million held by the operating facility).

As at December 31, 2021, Hammerhead is 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's assets.

Amounts borrowed under the amended credit facility bear interest at the Company's option based on the referenced Canadian prime lending rate, plus an applicable margin, or the bankers' acceptance rate in effect. 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 are the applicable prime and acceptance rates:

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

Term Debt

(Cdn$ thousands)	**December 31, 2021**	December 31, 2020
2020 Senior Notes – unsecured[1]	**152,174**	152,174
Redemption of principal	**(31,526)**	(31,526)
Paid-in-kind interest	**23,374**	8,714
Foreign exchange revaluation[2]	**(9,275)**	(8,927)
Total carrying value of long-term debt	**134,747**	120,435

1. The 2020 Senior Notes principal value of US$112.0 million was translated at the June 19, 2020 foreign exchange rate of 1.3587.
2. The 2020 Senior Notes are issued in US dollars and are revalued to Canadian dollars at each reporting period, using the period end foreign exchange rate. Changes in the foreign exchange rate will increase or decrease the Canadian dollar liability. The foreign exchange impact is recognized as an unrealized gain or loss in the consolidated statements of profit (loss) each reporting period.

On July 10, 2017, the Company issued US$160.0 million unsecured senior notes due July 10, 2022 through a private placement (the "2017 Senior Notes"). Proceeds net of fees, discounts and costs totaled US$148.0 million. The 2017 Senior Notes were carried at amortized cost, net of discounts and debt issue costs of US$12.0 million and C$0.3 million. The 2017 Senior Notes bore interest at 9% per annum, payable semi-annually in arrears on July 15 and January 15.

On June 19, 2020, the Company amended its existing senior note agreement whereby the holders of the 2017 Senior Notes approved an initial debt redemption of US$48.0 million, reducing the aggregate principal balance owing from US$160.0 million to US$112.0 million (the "2020 Senior Notes"). The maturity date of the 2020 Senior Notes was extended to July 10, 2024 and bears interest at 12% per annum. Under the amended agreement, the Company has the option of paying interest as cash or as paid-in-kind ("PIK"). PIK interest is added to the principal payable balance of the 2020 Senior Notes and is due on maturity. Under the 2020 Senior Notes agreement, the Company was granted an additional debt redemption of US$24.0 million, subject to the receipt of an additional equity draw on the June 2020 Investment Agreement on or before September 30, 2020. On September 29, 2020, the Company received an additional equity investment of $25.0 million and subsequently redeemed US$24.0 million related to the 2020 Senior Notes principal balance on October 10, 2020 for a total cost of US$1.0 dollar.

The June 19, 2020 debt redemption of US$48.0 million related to the 2017 Senior Notes was treated as a debt extinguishment in accordance with IFRS 9 Financial Instruments, as the debt redemption resulted in substantially different terms and cash flows.

If a change of control or a specified asset disposition occurs, each holder of the 2020 Senior Notes has the right to require the Company 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.

There are no maintenance financial covenants; however, there are standard business operating covenants, as well as covenants that may limit the Company's ability to incur additional debt. As at December 31, 2021, the Company was in compliance with all covenants related to the 2020 Senior Notes.

June 2020 Equity Commitment

On June 17, 2020, the Company entered into an investment agreement ("the June 2020 Investment Agreement") with an affiliate of its controlling shareholder. Under the June 2020 Investment Agreement, the Company has 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. The preferred shares have been classified as equity.

Under the June 2020 Investment Agreement, draws on the remaining equity commitment are subject to approval of the controlling shareholder and satisfaction of terms and conditions, at any time prior to June 17, 2024. On February 5, 2021 the Company received an additional equity investment of $33.7 million cash proceeds in exchange for the issuance of 67.4 million Series IX first preferred shares.

			(Cdn$ thousands)			
				Issue Costs		
		Number of Shares *(000's)*	Gross Cash Proceeds	Non-cash	Cash	Net Cash Proceeds
June 17, 2020	Initial draw	150,000	75,000	—	(1,125)	73,875
	Common share warrants [1]	—	—	(10,530)	—	—
September 29, 2020	Second draw	50,000	25,000	—	(14)	24,986
As at December 31, 2020		200,000	100,000	(10,530)	(1,139)	98,861
February 5, 2021	Third draw	**67,405**	**33,702**	**—**	**(22)**	**33,680**
As at December 31, 2021		**267,405**	**133,702**	**(10,530)**	**(1,161)**	**132,541**

1. The initial valuation of the common share purchase warrants was treated as a transaction cost with all subsequent adjustments to the valuation of the warrants recognized through the consolidated statements of profit (loss).

December 2020 Equity Commitment

On December 8, 2020, the Company entered into an investment agreement ("the December 2020 Investment Agreement") with an affiliate of one of its shareholders ("the Investor"). Under the December 2020 Investment Agreement, the Company has 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. The preferred shares have been classified as equity.

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. The Investor may be required to invest all or a portion of the remaining equity commitment at any time prior to June 17, 2024, subject to further investment made by an affiliate of the controlling shareholder under the June 2020 Investment Agreement.

			(Cdn$ thousands)			
				Issue Costs		
		Number of Shares *(000's)*	Gross Cash Proceeds	Non-cash	Cash	Net Cash Proceeds
December 8, 2020	Initial draw	7,700	3,850	—	(199)	3,651
	Common share warrants [1]	—	—	(405)	—	—
As at December 31, 2020		7,700	3,850	(405)	(199)	3,651
February 5, 2021	Second draw	**2,595**	**1,298**	**—**	**—**	**1,298**
As at December 31, 2021		**10,295**	**5,148**	**(405)**	**(199)**	**4,949**

1. The initial valuation of the common share purchase warrants was treated as a transaction cost with all subsequent adjustments to the valuation of the warrants recognized through the consolidated statements of profit (loss).

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 or replacing existing 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 Company believes that its current financial obligations including current commitments and working capital deficit (as defined in "Other Advisories") will be adequately funded by the available borrowing capacity and equity commitments, and funds from operations. Combined with its initiatives to reduce its capital, operating and G&A expense, the Company believes it has the necessary liquidity to meet its short-term operational needs.

Working Capital and Adjusted Working Capital

(Cdn$ thousands)	**December 31, 2021**	December 31, 2020
Current assets	**64,712**	44,251
Current liabilities	**(141,240)**	(233,890)
Working capital deficit	**(76,528)**	(189,639)
Current portion of bank debt	**—**	163,600
Adjusted working capital deficit[1]	**(76,528)**	(26,039)

1. Non-IFRS measure – see below under "Other Advisories - Non-IFRS Measures".

Available Funding

(Cdn$ thousands)	**December 31, 2021**	December 31, 2020
Working capital deficit	**(76,528)**	(189,639)
Debt capacity	**68,700**	16,090
Equity commitment[1,2]	**172,700**	207,700
Available funding[3]	**164,872**	34,151

1. As at December 31, 2021, the remaining equity commitment under the June 2020 Investment Agreement was $166.3 million (December 31, 2020 - $200.0 million).
2. As at December 31, 2021, the remaining equity commitment under the December 2020 Investment Agreement was $6.4 million (December 31, 2020 - $7.7 million).
3. Non-IFRS measure – see below under "Other Advisories - Non-IFRS Measures".

Net Debt and Total Capitalization

(Cdn$ thousands)	**December 31, 2021**	December 31, 2020
Bank debt	**106,300**	163,600
Term debt	**134,747**	120,435
Adjusted working capital deficit	**76,528**	26,039
Total net debt[1]	**317,575**	310,074
Shareholders' equity	**1,043,358**	1,061,017
Total capitalization[1]	**1,360,933**	1,371,091

1. Non-IFRS measure – see below under "Other Advisories - Non-IFRS Measures".

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. 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. Adjusted EBITDA is not a standardized measure and therefore may not be comparable with the calculation of similar measures by other entities.

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 it's capital structure and financing requirements. Net Debt, and Net Debt to Adjusted EBITDA are not standardized measures and therefore may not be comparable with the calculation of similar measures by other entities.

Net Debt to Adjusted EBITDA - Three Months and Year Ended

	Three Months Ended December 31,		Year Ended December 31,	
(Cdn$ thousands)	**2021**	2020	2021	2020
Operating netback	**51,653**	44,683	**161,274**	177,991
G&A expense	**(6,641)**	(8,514)	**(21,565)**	(21,838)
Adjusted EBITDA[1]	**45,012**	36,169	**139,709**	156,153
Net debt to Adjusted EBITDA[1,2]	**1.8**	2.1	**2.3**	2.0

1. Non-IFRS measure – see below under "Other Advisories - Non-IFRS Measures".
2. Net debt to Adjusted EBITDA is calculated as the total net debt over the annualized Adjusted EBITDA.

Hammerhead's ratio of net debt to Adjusted EBITDA was 2.3 for the year ended December 31, 2021 (December 31, 2020 – 2.0). Net debt to Adjusted EBITDA was higher for the year ended December 31, 2021 primarily due to the Company's lower operating netback when compared with the year ended December 31, 2020.

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, 2021**	December 31, 2020
Salaries, bonuses, benefits and director fees	**4,852**	4,101
Share-based compensation	**9,071**	5,259
Total key management compensation	**13,923**	9,360

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

At December 31, 2021, $5.6 million in limited recourse loans previously advanced to key management personnel remained outstanding (December 31, 2020 - $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, 2020 – $0.1 million).

Contractual Obligations and Commitments

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

(Cdn$ thousands)	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter	Total
Office buildings[1]	912	912	788	763	763	763	4,901
Firm transportation & processing	94,533	101,171	98,816	87,740	67,357	219,767	669,384
Total annual commitments	95,445	102,083	99,604	88,503	68,120	220,530	674,285

1. Relates to non-lease components and non-indexed variable payments.

Supplemental Information
Financial – Quarterly extracted information

(Cdn$ thousands, except per share amounts, production and unit prices)	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Q4 2020	Q3 2020	Q2 2020	Q1 2020
OPERATING								
Production Volumes								
Crude oil (bbls/d)	7,135	5,854	7,317	6,968	7,177	7,976	7,015	9,030
Natural gas (Mcf/d)	101,028	95,304	104,784	109,122	114,330	121,158	103,459	106,715
Natural gas liquids (bbls/d)	3,787	3,014	3,864	4,967	4,192	4,158	2,913	3,363
Total (boe/d)	27,760	24,752	28,645	30,122	30,424	32,327	27,171	30,179
Liquids weighting %	39	36	39	40	37	38	37	41
Average Realized Prices								
Crude oil ($/bbl)	92.34	83.80	77.21	66.89	49.91	45.72	25.80	52.01
Natural gas ($/Mcf)	5.88	4.77	3.52	3.67	3.12	2.49	2.23	2.35
Natural gas liquids ($/bbl)	68.60	58.12	47.30	40.57	29.81	25.63	18.09	24.32
Total ($/boe)	54.50	45.25	38.96	35.43	27.59	23.89	17.08	26.59
Operating Netback ($/boe)								
Realized price	54.50	45.25	38.96	35.43	27.59	23.89	17.08	26.59
Royalties	(5.68)	(4.41)	(3.22)	(2.07)	(2.40)	(1.06)	(1.07)	(1.70)
Operating expense	(8.38)	(9.27)	(7.93)	(7.21)	(6.49)	(6.65)	(8.77)	(6.49)
Net transportation expense	(6.04)	(6.83)	(6.32)	(5.32)	(4.96)	(5.29)	(5.60)	(4.93)
Operating netback, excluding realized (losses) gains on risk management contracts	34.40	24.74	21.49	20.83	13.74	10.89	1.64	13.47
Realized (losses) gains on risk management contracts	(14.18)	(11.73)	(7.30)	(4.97)	2.23	4.69	13.28	4.76
Operating netback	20.22	13.01	14.19	15.86	15.97	15.58	14.92	18.23
FINANCIAL								
Funds from operations	30,309	22,654	28,854	32,636	32,986	38,818	21,021	36,662
Per common share – basic	0.08	0.06	0.07	0.08	0.08	0.10	0.05	0.09
Per common share – diluted	0.03	0.06	0.07	0.08	0.04	0.10	0.05	0.06
Cash provided by operating activities	33,540	25,492	31,701	29,851	34,114	31,350	26,072	28,150
Per common share – basic	0.09	0.07	0.08	0.08	0.09	0.08	0.07	0.07
Per common share – diluted	0.03	0.07	0.08	0.08	0.04	0.08	0.07	0.04
Net profit/(loss)	37,139	(25,319)	(50,016)	(33,625)	22,600	(31,740)	(9,533)	72,083
Per common share – basic	0.09	(0.06)	(0.13)	(0.09)	0.06	(0.08)	(0.02)	0.18
Per common share – diluted	0.04	(0.06)	(0.13)	(0.09)	0.03	(0.08)	(0.02)	0.11
Oil and gas sales revenue	139,183	103,047	101,551	96,062	77,210	71,046	42,227	73,031
BALANCE SHEET								
Capital expenditures								
Drilling and completion	54,305	29,820	7,224	12,702	13,522	153	6,718	43,550
Equipment, facilities and pipelines	9,470	7,356	1,963	3,953	6,791	1,004	2,643	10,573
Workovers and maintenance	3,319	1,036	623	873	474	1,011	1,271	3,001
Land and other	—	—	1	—	—	—	—	44
Capitalized overhead and other	1,291	1,394	1,559	1,655	771	305	973	1,558
Capital expenditures	68,385	39,606	11,370	19,183	21,558	2,473	11,605	58,726
Total assets	1,473,551	1,416,666	1,408,592	1,452,262	1,459,912	1,470,930	1,528,211	1,615,720
Total liabilities	430,193	414,319	385,463	383,913	398,895	439,709	491,590	645,445
Working capital deficit	76,528	91,800	63,522	165,444	189,639	86,306	116,623	243,722
Available funding	164,872	165,100	184,492	38,157	34,151	116,740	111,103	(47,056)
Bank debt - credit facility outstanding	106,300	90,800	98,800	118,800	163,600	192,000	222,300	290,000
Term debt – Senior Notes[1]	134,747	131,567	124,272	122,503	120,435	154,459	153,193	226,992
Net debt	317,575	314,167	286,594	287,947	310,074	347,765	377,116	470,714
Shareholders' equity	1,043,358	1,002,347	1,023,129	1,068,349	1,061,017	1,031,221	1,036,621	970,275
Total capitalization	1,360,933	1,316,514	1,309,723	1,356,296	1,371,091	1,378,986	1,413,737	1,440,989
Weighted average common shares outstanding								
Basic	391,117	391,113	391,113	391,080	391,038	391,038	391,038	391,095
Diluted	1,005,039	391,113	391,113	391,080	896,778	391,038	391,038	640,422

1. The term debt - Senior Notes refers to the outstanding balance of the 2017 Senior Notes in Q1 2020, and the 2020 Senior Notes for all subsequent quarters. The balance above for the 2017 Senior Notes excludes the unamortized discount and debt issue costs from the total carrying value of the term debt.

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. The Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures, as defined by National Instrument 52-109 to provide reasonable assurance that (i) material information relating to the Company is made known to the Company’s Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual and interim financial statements and MD&A are prepared; and (ii) information required to be disclosed by the Company in its annual financial statements and MD&A and interim financial statements and MD&A is recorded, processed, summarized and reported as if the Company was subject to the time periods specified in securities legislation for issuer's that have securities listed and posted for trading on the TSX Venture Exchange. As at December 31, 2021, 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, 2021. 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 Company’s Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal controls over financial reporting as defined in NI 52-109. 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”). There have been no changes in the Company's internal controls over financial reporting during the period from January 1, 2021 to December 31, 2021 that have materially affected or are reasonably likely to materially affect the Company's internal controls over financial reporting. As at December 31, 2021, the Chief Executive Officer and the Chief Financial Officer evaluated the effectiveness of the design and operation of the Company’s internal controls over financial reporting. Based on their evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company’s internal controls over financial reporting were effective as at December 31, 2021. All control systems by their nature can only provide reasonable, but not absolute, assurance that the objectives of the control system are met.

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; terms of the 2020 Senior Notes; terms of the June 2020 Investment Agreement and December 2020 Investment Agreement; factors affecting the prices that Hammerhead receives for its crude oil and field condensate production; the Company's objectives for managing capital, including the Company's short-term capital management objective; the Company's belief that it is well positioned to execute its business strategy; expected sources of funding for future capital expenditures; current commitments and working capital deficit; the Company's beliefs regarding the availability of funding and liquidity to meet its financial obligations and short-term operational needs; the determination of the Company’s depletion and depreciation rates; the Company's contractual obligations and short-term operational needs; 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.

Statements relating to "reserves" are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves described can be profitably produced in the future. The recovery and reserve estimates of the Company's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil reserves may eventually prove to be greater than, or less than, the estimates provided herein.

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 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; and the impact (and duration thereof) that the COVID-19 pandemic will have on: (i) the demand for crude oil, NGLs 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, NGLs and natural gas. 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; 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; 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 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.

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 of the business. 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:

- HHR is committed to maintaining a strong balance sheet along with an adaptable capital expenditure program; however, any substantial and extended decline in the price of oil and natural gas could have an adverse effect on the

Company's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Commodity prices may be volatile for a variety of reasons including market uncertainties over the supply and demand due to the current state of the world economies, the ongoing COVID-19 pandemic, actions taken by the Organization of the Petroleum Exporting Countries, political uncertainties, sanctions imposed on certain oil producing nations by other countries and conflicts in other countries. Prices for oil and natural gas are also subject to the availability of foreign markets and the Company's ability to access such markets. Lower commodity prices restrict the Company's cash flow resulting in less funds from operations being available to fund the Company's capital expenditure budget. Consequently, the Company may not be able to replace its production with additional reserves, or the Company may elect not to produce from certain wells at lower prices and both the Company's production and reserves could potentially be reduced on a year-over-year basis. Any decrease in value of the Company's reserves may reduce the borrowing base under its Credit Facilities, which, depending on the level of the Company's indebtedness, could result in the Company having to repay a portion of its indebtedness. In addition to possibly resulting in a decrease in the value of the Company's economically recoverable reserves, lower commodity prices may also result in a decrease in the value of the Company's infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of the Company's oil and natural gas assets on its balance sheet and the recognition of an impairment charge in its income statement. Under the terms of the Credit Facilities, there would be an event of default on the part of the Company if its liability management rating falls below a certain threshold or if the Company becomes subject to an abandonment and reclamation order and its estimated cost of compliance with such order exceeds a certain threshold. Further, the Company will be restricted from acquiring certain assets with abandonment and reclamation liabilities over a certain threshold.

- 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. HHR can reduce the impact of such fluctuations in prices by maintaining an appropriate hedging strategy and entering into oil and natural gas risk management contracts from time to time. Such hedging arrangements can also expose the Company to 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, the 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 amount of oil and natural gas that the Company can produce and sell is subject to the accessibility, availability, proximity and capacity of gathering and processing facilities, pipeline systems, trucking and railway lines and loading terminals. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Company’s production, operations and financial results. Further, announcements and actions taken by the federal and provincial governments relating to the approval of infrastructure projects and related legal challenges may continue to impact the oil and natural gas transportation market.

- The long-term commercial success of the Company depends on its ability to find, develop and produce oil and natural gas reserves in an economic manner. HHR utilizes a team of highly qualified professionals with expertise and experience in the Company’s core areas and who have a vested interest in the success of the Company.

- The Company’s ability to successfully execute capital projects and market its oil and natural gas depends on a number of factors including, but not limited to, obtaining regulatory approvals or consents, acquiring and disposing of assets, availability of drilling rigs and related equipment and the skilled labour to operate them, availability of processing, storage or transportation capacity and the effects of inclement weather. The Company may be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces as a result of these factors.

- The Company is exposed to all the risks and hazards typically associated with operating an oil and gas well including fires, explosions, blowouts, spills, sour gas releases or other dangerous conditions that could result in personal injury and damage to the environment or HHR’s property and equipment. The Company maintains and strictly enforces an environmental, health and safety program to address these operational risks. Further, HHR maintains a comprehensive insurance plan which includes liability insurance, where available, in amounts consistent with industry standards.

- The Company undertakes certain waterflooding programs, which involve the injection of water or other liquids into an oil reservoir to increase production from the reservoir and to decrease production declines. To undertake such waterflooding activities the Company needs to have access to sufficient volumes of water, or other liquids, to pump into the reservoir to increase the pressure in the reservoir. There is no certainty that the Company will have access to the required volumes of water and in certain areas there may be restrictions on water use for activities such as waterflooding. If the Company is unable to access such water it may not be able to undertake waterflooding activities, which may reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reservoirs. In addition, the Company may undertake certain waterflood programs that ultimately prove unsuccessful in increasing production from the reservoir.

- The Company is exposed to currency risk as world oil prices are quoted in US dollars. The price received by Canadian producers is therefore affected by the Canadian/US dollar exchange rate, which may fluctuate over time. A material increase in the value of the Canadian dollar would, other variables remaining constant, negatively impact HHR’s net production revenue. Subject to compliance with its debt instruments, HHR may reduce the impact of such fluctuations by entering into agreements to fix the exchange rate of Canadian to US dollars in order to offset this risk. However, if the Canadian dollar declined in value compared to such fixed currencies, HHR would not benefit from the fluctuating rate.

- Global climate issues continue to attract public and scientific attention. Numerous reports, including reports from the Intergovernmental Panel on Climate Change, have engendered concern about the impacts of human activity, especially hydrocarbon combustion, on global climate issues. In turn, increasing public, government, and investor attention is being paid to global climate issues and to emissions of greenhouse gases ("GHG"), including emissions of carbon dioxide and methane from the production and use of oil, liquids and natural gas. The majority of countries across the globe, including Canada, have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In addition, during the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact. The Company faces risks associated with climate change and climate change policy and regulations.

- All phases of the oil and natural gas business present environmental risks and hazards and HHR is subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on restricting emissions commonly referred to as GHG emissions and promoting adaptation to climate change and the transition to a low-carbon economy. It is not possible to predict what measures foreign and domestic governments may implement in this regard, nor is it possible to predict the requirements that such measures may impose or when such measures may be implemented. However, international multilateral agreements, the obligations adopted thereunder and legal challenges concerning the adequacy of climate-related policy brought against foreign and domestic governments may accelerate the implementation of these measures. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Given the evolving nature of climate change policy and the control of GHG emissions and resulting requirements, including carbon taxes and carbon pricing schemes implemented by varying levels of government, it is expected that current and future climate change regulations will have the effect of increasing the Company's operating expense, and, in the long-term, potentially reducing the demand for oil, liquids, natural gas and related products, resulting in a decrease in the Company's profitability and a reduction in the value of its assets or requiring asset impairments for financial statement purposes. The direct or indirect costs of compliance with greenhouse gas-related regulations may have a material adverse effect on the Company’s business, financial condition, results of operations and prospects. The Company is committed to conducting transparent, safe and responsible operations in the communities in which its people live and work.

- Concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels, which has influenced investors' willingness to invest in the oil and natural gas industry. Historically, political and legal opposition to the fossil fuel industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to more directly hold governments and oil and natural gas companies responsible for climate change through climate litigation. Claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under certain laws or that such energy companies provided misleading disclosure to the public and investors of current or future risks associated with climate change. As a result, individuals, government authorities, or other organizations may make claims against oil and natural gas companies, including the Company, for alleged personal injury, property damage, or other potential liabilities. While the Company is not a party to any such litigation or proceedings, it could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely affect the demand for and price of securities issued by the Company, impact its operations and have an adverse impact on its financial condition.

- Various levels of governments impose extensive controls and regulations on oil and natural gas operations (exploration, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. Further, ongoing third party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed, resulting in uncertainty and interruption to the business of the oil and natural gas industry. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Company's costs, either of which may have a material adverse effect on HHR's business, financial condition, results of operations or cash flow.

- The economics of the Company's projects could be impacted by a new or modified royalty regime. An increase in royalties would reduce the Company's earnings and could make future capital investments, or the Company's operations, less economic.

- The Company's results can be adversely impacted by political, legal, or regulatory developments in Canada and elsewhere that affect local operations and local and international markets. Changes in government, government policy or regulations, changes in law or interpretation of settled law, third-party opposition to industrial activity generally or projects specifically, and duration of regulatory reviews could impact the Company's existing operations and planned projects. This includes actions by regulators or other political actors to delay or deny necessary licenses and permits for the Company's activities or restrict the operation of third-party infrastructure that the Company relies on. Additionally, changes in environmental regulations, assessment processes or other laws, and increasing and expanding stakeholder consultation (including Indigenous stakeholders), may increase the cost of compliance or reduce or delay available business opportunities and adversely impact the Company's results. Other government and political factors that could adversely affect the Company's financial results include increases in taxes or government royalty rates (including retroactive claims) and changes in trade policies and agreements. Further, the adoption of regulations mandating efficiency standards, and the use of alternative fuels or uncompetitive fuel components could affect the Company's operations. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels or technologies. Governments and others are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources, and the success of these initiatives may decrease demand for the Company's products. A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy. The oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding oil and natural gas development—particularly with respect to infrastructure projects. Protests, blockades and demonstrations have the potential to delay and disrupt the Company's activities.

- The Company has become increasingly dependent upon the availability, capacity, reliability and security of its information technology infrastructure and its ability to expand and continually update this infrastructure, to conduct daily operations. The Company depends on various information technology systems to estimate reserve quantities, process and record financial data, manage its land base, manage financial resources, analyze seismic information, administer the Company's contracts with its operators and lessees and communicate with employees and third-party partners. Further, the Company is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Company's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to HHR's business activities or its competitive position. Disruption of critical information technology services, or breaches of information security, could have a negative effect on the Company's performance and earnings, as well as on its reputation, and any damages sustained may not be adequately covered by the Company's current insurance coverage, or at all. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Company's business, financial condition, results of operations and cash flows.

- The Company's business, financial condition and results of operations could be materially and adversely affected by the outbreak of epidemics, pandemics and other public health crises in geographic areas in which we have operations, suppliers, customers or employees. In March 2020, the World Health Organization declared COVID-19 a global pandemic, prompting many countries around the world to close international borders and order the closure of institutions and businesses deemed non-essential. This resulted in a swift and significant reduction in economic activity in Canada and internationally along with a sudden drop in demand for oil, liquids and natural gas. Since 2020, oil prices have largely recovered from their historic lows, but price support from future demand remains uncertain as countries experience varying degrees of virus outbreak and newly emerging virus variants following efforts to re-open local economies and international borders. Low commodity prices resulting from reduced demand associated with the impact of COVID-19 has had, and may continue to have, a negative impact on the Company's operational results and financial condition. Low prices for oil, liquids and natural gas will reduce the Company's funds from operations, and impact the Company's level of capital investment and may result in the reduction of production at certain producing properties. While the duration and full impact of the COVID-19 pandemic is not yet known, effects of COVID-19 may also include disruptions to production operations, access to materials and services, increased employee absenteeism from illness, and temporary closures of the Company's facilities. The extent to which the Company's operational and financial results are affected by COVID-19 will depend on various factors and consequences beyond its control such as the duration and scope of the pandemic; additional actions taken by business and government in response to the pandemic, and the speed and effectiveness of responses to combat the virus. Additionally, COVID-19 and its effect on local and global economic conditions stemming from the pandemic could also aggravate the other risk factors identified herein, the extent of which is not yet known.

- In February 2022, Russian military forces invaded Ukraine. In response, Ukrainian military personal and civilians are actively resisting the invasion. Many countries throughout the world have provided aid to the Ukraine in the form of financial aid and in some cases military equipment and weapons to assist in their resistance to the Russian invasion. The North Atlantic Treaty Organization ("NATO") has also mobilized forces to NATO member countries that are close to the conflict as deterrence to further Russian aggression in the region. The outcome of the conflict is uncertain and is likely to have wide-ranging consequences on the peace and stability of the region and the world economy. In addition, certain countries including Canada and the United States, have imposed strict financial and trade sanctions against Russia, which sanctions may have far reaching effects on the global economy. As part of the sanctions package, the German government paused the certification process for the 1,200 km Nord Stream 2 natural gas pipeline that was built to carry natural gas from Russia to Germany. Russia is a major exporter of oil and natural gas. Disruption of supplies of oil and natural gas from Russia could cause a significant worldwide supply shortage of oil and natural gas and have a significant impact on worldwide prices of oil and natural gas. A lack of supply and high prices of oil and natural gas could have a significant adverse impact on the world economy. The long-term impacts of the conflict and the sanctions imposed on Russia remain uncertain.

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.

References to HHR's 2020 reserves herein are from the reserves evaluation was conducted by McDaniel dated March 31, 2021 with an effective date of December 31, 2020, which was prepared in accordance with definitions, standards and procedures contained in the COGE Handbook and NI 51-101. All December 31, 2020 reserves are based on a three consultant average price forecast (McDaniel, GLJ and Sproule) effective January 1, 2021.

"Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. "Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. All references to oil production and reserves contained herein are in respect of light and medium crude oil production and reserves and references to gas production and reserves contained herein are in respect of conventional natural gas production and reserves

Estimates of the net present value of the future net revenue from the Company's reserves do not represent the fair market value of the Company's reserves. The estimates of reserves and future net revenue from individual properties or wells may not reflect the same confidence level as estimates of reserves and future net revenue for all properties and wells due to the effects of aggregation.

This MD&A contains certain oil and gas metrics, including operating netback, F&D costs, and recycle ratio, 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. F&D costs are calculated by dividing capital expenditures by the change in reserves within the applicable reserves category. F&D costs, including future development capital, include all capital expenditures in the year as well as the change in future development capital required to bring the reserves within the specified reserves category on production. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total F&D costs related to reserve additions for that year. Recycle ratio is calculated as netback divided by F&D costs.

Non-IFRS 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 measures do not have any standardized meanings and should not be used to make comparisons between Hammerhead and other companies without also considering any differences in the method by which the calculations are prepared. The non-IFRS measures used in this report are summarized as follows:

Operating netback

Operating netback is calculated on a per boe basis and is determined by deducting royalties, operating expense, net transportation, and realized (losses) gains from risk management contracts from oil and natural gas sales. Operating netback is utilized by Hammerhead to assess the profitability of the Company's liquids and natural gas assets and to compare current results to prior periods or to peers by isolating for the impact of changes in production volumes.

Adjusted working capital and available funding

Adjusted working capital is comprised of current assets less current liabilities on the Company's balance sheet, including the current portion of risk management contracts, and excludes the current portion of the credit facilities. Adjusted working capital is included within the non-GAAP measures because a surplus of adjusted working capital will result in a future net cash inflow to the business which can be used for future funding and a deficiency of adjusted working capital will result in a future net cash outflow which may require a future draw from Hammerhead’s existing funding capacity in order to settle the short-term liabilities in excess of current assets. The available funding measure allows management and other users to evaluate the Company’s liquidity. Available funding is comprised of working capital, the undrawn component of Hammerhead’s Credit Facilities, plus the remaining equity commitment related to any outstanding Investment Agreements.

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, extraordinary and non-recurring items. See the table below for a reconciliation of all adjusting items impacting Adjusted EBITDA. Hammerhead utilizes adjusted EBITDA as a measure of operational performance and cash flow generating capability. Adjusted EBITDA impacts the level and extent of funding for capital projects, investments or returning capital to shareholders. This measure is consistent with the adjusted EBITDA formula prescribed under the Company's credit facility and allows Hammerhead and others to evaluate the impact of the Company's earnings on its financial covenants and assess its ability to fund financing expenses and other obligations.

The following is a reconciliation of Adjusted EBITDA to the nearest IFRS measure, net profit (loss) before income tax:

	Three Months Ended December 31,			Year Ended December 31,		
(Cdn$ thousands)	2021	2020	% Change	2021	2020	% Change
Net profit (loss) before income tax	37,139	22,600	64	(71,821)	53,410	(234)
Add (deduct):						
Unrealized (gain) loss on risk management contracts	(46,238)	9,836	(570)	16,649	18,353	(9)
Optimization fees	13,665	—	100	19,708	670	2,841
Share-based compensation	2,757	3,419	(19)	14,039	7,155	96
Depletion and depreciation	33,376	34,650	(4)	127,333	135,184	(6)
Finance expense	5,384	7,072	(24)	21,264	37,344	(43)
(Gain) loss on foreign exchange	(621)	(6,161)	(90)	(350)	817	(143)
Loss (gain) on warrant liability	6	11	(45)	96	(3,981)	(102)
Gain on debt redemptions of financial liabilities	—	(31,514)	—	—	(88,160)	—
Loss on asset disposition	—	—	—	13,813	—	—
Other income, excluding transportation income	(456)	(3,744)	(88)	(1,022)	(4,639)	(78)
Adjusted EBITDA	45,012	36,169	24	139,709	156,153	(11)

Net debt and net debt to Adjusted EBITDA

Net debt is calculated as the outstanding balance on the Company's credit facility, the 2020 Senior Notes and adjusted working capital. The 2020 Senior Notes are calculated as the principal amount outstanding, plus accrued PIK interest, converted to Canadian dollars at the closing exchange rate for the period. Net debt is a measure commonly used in the oil and gas industry for assessing the liquidity risk of a company. Net debt to Adjusted EBITDA is Adjusted EBITDA annualized over net debt.

Total capitalization

Total capitalization consists of net debt and the carrying value of the Company's shareholders' equity. Total capitalization is utilized to analyze balance sheet strength, liquidity and composition. Hammerhead utilizes the net book value of the Company's shareholders' equity in order to better align the total capitalization measure with the figures that are presented in the consolidated statements of financial position.

Funds from operations, funds from operations per boe and funds from operations per share and diluted share

Funds from operations is comprised of cash provided by operating activities, excluding the impact of changes in non-cash working capital. Hammerhead utilizes funds from operations as a measure of operational performance and cash flow generating capability. Funds from operations also impacts the level and extent of funding for investment in capital projects, repaying debt and returning capital to shareholders. By excluding changes in non-cash working capital from cash provided by operating activities, the funds from operations measure provides a meaningful metric for Management and others by establishing a clear link between the Company's cash flows, statement of profit (loss) and operating netbacks from the business by isolating the impact of changes in the timing between accrual and cash settlement dates. Funds from operations as presented is not intended to represent cash flow from operating activities, net profits or other measures of financial performance calculated in accordance with IFRS.

The following table reconciles cash flows from operating activities to funds from operations:

	Three Months Ended December 31,		Year Ended December 31,	
(Cdn$ thousands)	**2021**	2020	**2021**	2020
Cash flow from operating activities	**33,540**	34,114	**120,584**	119,686
Changes in non-cash working capital	**(3,231)**	(1,128)	**(6,131)**	9,801
Funds from operations	**30,309**	32,986	**114,453**	129,487

Funds from operations per boe is calculated by dividing funds from operations by the Company's total production. Funds from operations per boe can also be determined by deducting G&A, financing and other cash operating related overhead expenses on a per boe basis from the operating netback. Funds from operations per boe is utilized by Hammerhead to assess the profitability of the Company's liquids and natural gas 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 share and diluted share is calculated by dividing funds from operations by the Company's weighted average shares outstanding and the weighted average shares outstanding with dilutive effect of outstanding equity compensation units during the period.

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	Light crude oil and medium crude oil as defined in National Instrument 51-101
boe	barrels of oil equivalent	Natural gas	Conventional natural 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
GJ	gigajoule	RSUs	Restricted Share Units

CORPORATE INFORMATION

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Bryan Begley [2,3]

Robert Tichio [3,4]

Stewart Hanlon [1,4]

Paul Charron [1,2,3]

Jesal Shah [1]

E. Bartow Jones [2]

1 Member of Audit Committee
2 Member of Reserves Committee
3 Member of Compensation Committee
4 Member of Governance Committee

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Mike Kohut
Senior Vice President & Chief Financial Officer

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