Q3 2021

Hemisphere ENERGY

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Q3 2021 HIGHLIGHTS

- Generated record revenue of $10.4 million, a 77% improvement over the third quarter of 2020.
- Maintained production at 1,671 boe/d (99% heavy crude oil and 1% conventional natural gas), relatively flat compared to the third quarter of last year, despite the conversion of several oil producer wells to water injectors and minimal capital spending over the past year.
- Achieved an operating field netback before hedges of $39.25/boe for a total of $6.0 million, a 56% increase over the third quarter of 2020.
- Increased adjusted funds flow (AFF) from operations by 19% to $4.0 million, when compared to the third quarter of 2020.
- Lowered net debt to $18.2 million, a 33% reduction from the third quarter of 2020.
- Reduced net debt to AFF ratio to 1.1.

CORPORATE UPDATE

During the third quarter, Hemisphere invested just over $3.3 million in its Atlee Buffalo field operations. The majority of capital expenditures included a successful three well drilling program in the Atlee G Pool. The Company also acquired a Free Water Knockout (FWKO) vessel in anticipation of production growth at the G pool facility during the fourth quarter.

Hemisphere's new G pool wells are the first drilled by the Company since 2019 due to severe market volatility during 2020 and early 2021. After being brought online in late October, total oil production from the new wells has averaged approximately 300 bbl/d during the first two weeks of November. With the addition of these new wells and the continued success of Hemisphere's enhanced oil recovery projects, corporate production has increased to approximately 2,100 boe/d (99% heavy crude oil and 1% conventional natural gas), based on field estimates between November 1-15th.

Hemisphere's third quarter also marked two very important milestones for the Company, in both its field operations and financial structure.

At the start of the third quarter, the Company announced the implementation of its first polymer flood project in the Atlee G Pool in southeast Alberta. Reservoir simulation and analogue analysis indicate both increased production rates and higher recovery factors are predicted for the oil pool.

Subsequent to that, the Company announced the replacement of its previous five-year term loan with a new $35 million extendible two-year committed term facility with ATB Financial in July. The new facility provides Hemisphere with increased financial flexibility, a significant reduction in interest costs, and lower foreign exchange risk.

2021 FINANCIAL AND OPERATING HIGHLIGHTS

	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
FINANCIAL				
Petroleum and natural gas revenue	**$ 10,431,678**	$ 5,889,668	**$ 28,407,919**	$ 13,305,661
Operating field netback[(1)]	**6,032,734**	3,862,969	**17,805,554**	7,813,633
Operating netback[(2)]	**5,094,246**	4,718,540	**15,970,866**	10,899,880
Cash flow provided by operating activities	**5,472,918**	3,087,951	**13,417,137**	7,262,068
Adjusted funds flow from operations (AFF)[(3)]	**4,047,805**	3,406,613	**12,319,791**	6,914,887
Per share, basic[(3)]	**0.05**	0.04	**0.14**	0.08
Per share, diluted[(3)]	**0.04**	0.04	**0.13**	0.08
Net income (loss)	**2,308,838**	1,473,572	**482,425**	(269,553)
Per share, basic	**0.03**	0.02	**0.01**	(0.00)
Per share, diluted	**0.02**	0.02	**0.01**	(0.00)
Capital expenditures	**3,320,483**	392,199	**6,276,094**	1,067,373
Net debt[(4)]	**18,231,440**	27,363,336	**18,231,440**	27,363,336
Net debt to annualized AFF[(3)(4)]	**1.1**	2.0	**1.1**	3.0
Bank debt	**16,233,591**	-	**16,233,591**	-
Gross term loan[(5)]	**$ -**	$ 29,967,750	**$ -**	$ 29,967,750
Average daily production				
Heavy oil (bbl/d)	**1,652**	1,675	**1,683**	1,754
Natural gas (Mcf/d)	**110**	70	**124**	87
Combined (boe/d)	**1,671**	1,686	**1,704**	1,768
Oil weighting	**99%**	99%	**99%**	99%
Average sales prices				
Heavy oil ($/bbl)	**$ 68.39**	$ 38.14	**$ 61.60**	$ 27.59
Natural gas ($/Mcf)	**3.47**	2.13	**3.07**	2.01
Combined ($/boe)	**$ 67.87**	**$** 37.96	**$ 61.08**	$ 27.47
Operating netback ($/boe)				
Petroleum and natural gas revenue	**$ 67.87**	$ 37.96	**$ 61.08**	$ 27.47
Royalties	**(13.66)**	(3.75)	**(10.26)**	(2.28)
Operating costs	**(12.66)**	(6.79)	**(10.11)**	(6.53)
Transportation costs	**(2.30)**	(2.52)	**(2.42)**	(2.53)
Operating field netback[(1)]	**39.25**	24.90	**38.28**	16.13
Realized commodity hedging gain (loss)	**(6.11)**	5.51	**(3.94)**	6.37
Operating netback[(2)]	**$ 33.14**	$ 30.41	**$ 34.34**	$ 22.50
Adjusted funds flow from operations[(3)] ($/boe)	**$ 26.33**	$ 21.96	**$ 26.49**	$ 14.27

Notes:
(1) Operating field netback is a non-IFRS measure calculated as the Company's oil and gas sales, less royalties, operating expenses and transportation costs on an absolute and per barrel of oil equivalent basis.
(2) Operating netback is a non-IFRS measure calculated as the operating field netback plus the Company's realized commodity hedging gain (loss) on an absolute and per barrel of oil equivalent basis.
(3) Adjusted funds flow from operations, is a non-IFRS measure that represents cash generated by operating activities, before changes in non-cash working capital and adjusted for any decommissioning expenditures, and may not be comparable to measures used by other companies.
(4) Net debt is a non-IFRS measure calculated as current assets minus current liabilities, excluding fair value of financial instruments, lease and warrant liabilities, plus bank debt or gross term loan.
(5) Gross term loan is calculated as the total USD draws, less any payments, on the term loan translated to Canadian Dollars at the period end exchange rate.

	Nine months ended September 30	
	2021	2020
SHARE CAPITAL		
Common shares outstanding	**88,229,802**	87,882,302
Stock options outstanding	**6,444,000**	8,584,000
Warrants outstanding	**13,750,000**	13,750,000
Fully Diluted	**108,423,802**	110,216,302
Weighted-average shares outstanding – basic	**87,892,439**	88,446,525
Weighted-average shares outstanding – diluted	**93,050,371**	89,174,530

MANAGEMENT'S DISCUSSION AND ANALYSIS

Dated as at November 18, 2021

The following Management's Discussion and Analysis ("MD&A") is a review of the operations and current financial position for the three and nine months ended September 30, 2021 for Hemisphere Energy Corporation ("Hemisphere" or the "Company") and should be read in conjunction with the unaudited interim condensed financial statements and related notes for the three and nine months ended September 30, 2021, and the audited annual financial statements and related notes for the year ended December 31, 2020. These documents and additional information relating to the Company, including the Company's Annual Information Form, are available on SEDAR at www.sedar.com or the Company's website at www.hemisphereenergy.ca.

The information in this MD&A is based on the unaudited interim condensed financial statements which were prepared in accordance with International Financial Reporting Standards ("IFRS") applicable to the preparation of unaudited interim condensed financial statements including IAS 34 "Interim Financial Reporting", as issued by the International Accounting Standards Board ("IASB").

This MD&A contains non-IFRS measures, additional IFRS measures and forward-looking statements. Readers are cautioned that this document should be read in conjunction with Hemisphere's disclosure under "Non-IFRS and additional IFRS Measures" and "Forward-Looking Statements" included at the end of this MD&A. All figures are in Canadian dollars unless otherwise noted.

Business Overview

Hemisphere produces oil and natural gas from its Atlee Buffalo and Jenner properties in southeast Alberta. The Company is headquartered in Vancouver, British Columbia and is traded on the TSX Venture Exchange under the symbol "HME" and on the OTCQX Best Market under the symbol "HMENF".

Atlee Buffalo, Alberta

The Company owns and operates all of its wells in the Atlee Buffalo area. The property is accessible year-round and is located north of Medicine Hat in southeastern Alberta. Hemisphere has a 100% working interest in 9,440 net acres.

Jenner, Alberta

Hemisphere owns and operates all of its wells and has a land position of 8,024 net acres in the Jenner area. The property is accessible year-round and is located 25 kilometers west of the Company's Atlee Buffalo property in southeastern Alberta.

Operating Results

The Company generated adjusted funds flow from operations[1] (AFF) of $4,047,805 ($0.05/share) during the third quarter of 2021, as compared to $3,406,613 ($0.04/share) during the third quarter of 2020. AFF

[1] *Adjusted funds flow from operations, is a non-IFRS measure that represents cash generated by operating activities, before changes in non-cash working capital and adjusted for any decommissioning expenditures, and may not be comparable to measures used by other companies.*

for the nine months ended September 30, 2021 increased to $12,319,791 ($0.14/share) from $6,914,887 ($0.08/share) for the same period in 2020.

The increase in AFF from operations for three and nine months ended September 30, 2021 is due primarily to a respective 79% and 122% increase in the combined average realized sales price over the respective comparable periods in 2020.

For the three and nine months ended September 30, 2021, the Company reported net income of $2,308,838 ($0.03/share) and $482,425 ($0.01/share), respectively, compared to net income of $1,473,572 ($0.02/share) and a net loss of $269,553 ($0.00/share) for the three and nine months ended September 30, 2020, respectively. This increase of $751,978 in the first nine months of 2021 is generally the result of an increase in field netbacks of $9,991,921 and nil impairments ($3,859,110 in 2020), offset by an increase in warrant liability revaluation of $3,858,812 as well as increases in realized and unrealized hedge losses of $4,920,935 and $5,482,531 respectively.

Production

	Three Months Ended September 30		Nine Months Ended September 30	
By product:	**2021**	2020	**2021**	2020
Oil (bbl/d)	**1,652**	1,675	**1,683**	1,754
Natural gas (Mcf/d)	**110**	70	**124**	87
Total (boe/d)	**1,671**	1,686	**1,704**	1,768
Oil weighting	**99%**	99%	**99%**	99%

In the third quarter of 2021, the Company's average daily production was 1,671 boe/d (99% oil) representing a slight 1% decrease from 1,686 boe/d (99% oil) over the comparable quarter in 2020. For the nine months ended September 30, 2021, the Company's average daily production was 1,704 boe/d (99% oil), representing a 4% decrease from 1,768 boe/d (99% oi) for the same period in 2020. This slight decrease can be attributed to the conversion of four wells in the Atlee G Pool from oil producing wells to water injectors over the past year, offset by the increase in production due to the expanded injection in the pool.

Average Benchmark and Realized Prices

	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Benchmark prices				
WTI ($US/bbl)[1]	**$ 70.56**	$ 40.93	**$ 64.81**	$ 38.31
Exchange rate (1 $US/$C)	**1.2595**	1.3316	**1.2509**	1.3528
WTI ($C/bbl)	**88.88**	54.50	**81.07**	51.83
WCS Diff ($C/bbl)	**17.10**	12.08	**15.68**	18.85
WCS ($C/bbl)[2]	**71.77**	42.41	**65.39**	32.98
AECO natural gas ($US/Mcf)[3]	**3.58**	2.27	**3.27**	2.10
Average realized prices				
Crude oil ($C/bbl)	**68.39**	38.14	**61.60**	27.59
Natural gas ($C/Mcf)	**3.47**	2.13	**3.07**	2.01
Combined ($C/boe)	**$ 67.87**	$ 37.96	**$ 61.08**	$ 27.47

Notes:
(1) Represents posting prices of West Texas Intermediate Oil.
(2) Represents posting prices of Western Canadian Select.
(3) Represents the Alberta 30 day spot AECO posting prices.

The Company's oil and natural gas sales and financial results are significantly influenced by changes in commodity prices. The West Texas Intermediate pricing ("WTI") at Cushing, Oklahoma is the benchmark reference price for North American crude oil prices. Canadian oil prices, including Western Canada Select ("WCS") and Hemisphere's crude oil, are based on price postings, which is WTI-adjusted for transportation, quality, and the currency conversion rates from United States dollar ("USD") to Canadian dollar.

The Company's combined average realized price increased by 79% to $67.87 from $37.96/boe during the comparable three months ended September 30, 2020. The Company's combined average realized price increased by 122% from $27.47/boe to $61.08/boe during the nine months ended September 30, 2021. This increase is the primarily the result of increases of $30.25/bbl and $34.01/bbl, respectively, in realized WTI prices for the three and nine month ended September 30, 2021 over the comparable periods in 2020.

As at the date of this MD&A, the Company held derivative commodity contracts as follows:

Product	**Type**	**Volume**	**Price**	**Index**	**Term**
Crude oil	Swap	800 bbl/d	US$58.45	WTI-NYMEX	Oct. 1, 2021 – Dec. 31, 2021
Crude oil	Swap	100 bbl/d	US$12.50	WCS Differential	Oct. 1, 2021 – Dec. 31, 2021
Crude oil	Swap	100 bbl/d	US$12.00	WCS Differential	Oct. 1, 2021 – Dec. 31, 2021
Crude oil	Swap	100 bbl/d	US$14.10	WCS Differential	Oct. 1, 2021 – Dec. 31, 2021
Crude oil	Swap	100 bbl/d	US$13.25	WCS Differential	Oct. 1, 2021 – Dec. 31, 2021
Crude oil	Swap	100 bbl/d	US$13.10	WCS Differential	Oct. 1, 2021 – Dec. 31, 2021
Crude oil	Swap	100 bbl/d	US$12.60	WCS Differential	Oct. 1, 2021 – Dec. 31, 2021
Crude oil	Swap	400 bbl/d	US$19.50	WCS Differential	Jan. 1, 2022
Crude oil	Swap	200 bbl/d	US$19.00	WCS Differential	Jan. 1, 2022 – Mar. 31, 2022
Crude oil	Swap	800 bbl/d	US$57.03	WTI-NYMEX	Jan. 1, 2022 – Mar. 31, 2022
Crude oil	3-Way	100 bbl/d	US$40.00(put)/US$50.00(put)/US $79(call)	WTI-NYMEX	Apr. 1, 2022 – Jun. 30, 2022
Crude oil	Swap	200 bbl/d	US$12.10	WCS Differential	Jan. 1, 2022 – Jun. 30, 2022
Crude oil	Put Spread	725 bbl/d	US$30.00(put sell)/US$40.00(put buy), net cost US$1.65/bbl	WTI-NYMEX	Apr. 1, 2022 – Aug. 31, 2022
Crude oil	Sold Call	200 bbl/d	US$78.25(call sell), net premium US$1.65/bbl	WTI-NYMEX	Apr. 1, 2022 – Aug. 31, 2022
Crude oil	Sold Call	100 bbl/d	US$78.70(call sell), net premium US$1.65/bbl	WTI-NYMEX	Apr. 1, 2022 – Aug. 31, 2022
Crude oil	Sold Call	200 bbl/d	US$82.10(call sell), net premium US$1.65/bbl	WTI-NYMEX	Apr. 1, 2022 – Aug. 31, 2022
Crude oil	Sold Call	100 bbl/d	US$86.50(call sell), net premium US$1.65/bbl	WTI-NYMEX	Apr. 1, 2022 – Aug. 31, 2022
Crude oil	Sold Call	125 bbl/d	US$88.40(call sell), net premium US$1.65/bbl	WTI-NYMEX	Apr. 1, 2022 – Aug. 31, 2022

At September 30, 2021 the commodity contracts were fair valued as a liability of $2,770,828 recorded on the balance sheet, and an unrealized gain for the three month period of $301,896 and an unrealized loss for the nine month period of $2,964,516, respectively (September 30, 2020 – loss of $1,319,060 and gain of $2,518,015 respectively).

Revenue

	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Oil	**$ 10,396,479**	$ 5,875,899	**$ 28,304,024**	$ 13,257,484
Natural gas	**35,200**	13,769	**103,895**	48,177
Total	**$ 10,431,678**	$ 5,889,668	**$ 28,407,919**	$ 13,305,661

The Company achieved record revenue for the three months ended September 30, 2021 of $10,431,678, which is an increase of 77% from the comparable period in 2020. For the nine months, revenue increased by 114% over the comparable period in 2020. These increases are due primarily to the $28.53 and $33.62 increases in the Company's combined average realized price over the comparable three and nine month periods in 2020.

Operating Netback

	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Operating netback				
Revenue	**$ 10,431,678**	$ 5,889,668	**$ 28,407,919**	$ 13,305,661
Royalties	**(2,100,349)**	(582,409)	**(4,772,742)**	(1,106,149)
Operating costs	**(1,945,354)**	(1,053,565)	**(4,702,374)**	(3,162,256)
Transportation costs	**(353,241)**	(390,725)	**(1,127,249)**	(1,223,623)
Operating field netback[1]	**$ 6,032,734**	$ 3,862,969	**$ 17,805,554**	$ 7,813,633
Realized commodity hedging gain (loss)	**(938,489)**	855,571	**(1,834,687)**	3,086,247
Operating netback[2]	**$ 5,094,246**	$ 4,718,540	**$ 15,970,866**	$ 10,899,880
Operating netback ($/boe)				
Revenue	**$ 67.87**	$ 37.96	**$ 61.08**	$ 27.47
Royalties	**(13.66)**	(3.75)	**(10.26)**	(2.28)
Operating costs	**(12.66)**	(6.79)	**(10.11)**	(6.53)
Transportation costs	**(2.30)**	(2.52)	**(2.42)**	(2.53)
Operating field netback[1]	**$ 39.25**	$ 24.90	**$ 38.28**	$ 16.13
Realized commodity hedging gain (loss)	**(6.11)**	5.51	**(3.94)**	6.37
Operating Netback[2]	**$ 33.14**	$ 30.41	**$ 34.34**	$ 22.50

Notes:

(1) Operating field netback is a non-IFRS measure calculated as the Company's oil and gas sales, less royalties, operating expenses and transportation costs on an absolute and per barrel of oil equivalent.

(2) Operating netback is a non-IFRS measure calculated as the operating field netback plus the Company's realized commodity hedging gain (loss) on an absolute and per barrel of oil equivalent.

Royalties were higher by $9.91/boe and $7.98 for the three and nine months ended September 30, 2021 over the third quarter of 2020. These higher royalties are due primarily to the result of significantly higher realized commodity prices year over year.

Operating costs include all costs for gathering, processing, dehydration, compression, water processing and marketing of the oil and natural gas, as well as additional costs incurred periodically for maintenance and repairs. Operating costs for the three and six months ended September 30, 2021 increased on a per boe basis by $5.87 and $3.58, or 86% and 55%, respectively over the comparable periods in 2020. The increase in operating costs can be attributed to startup costs of the polymer flood and the added cost of polymer.

Transportation costs include all costs incurred to transport emulsion, oil and gas sales to processing and distribution facilities. Transportation costs were $2.30/boe during the third quarter of 2021, which is a $0.22/boe or 9% decrease over the comparable quarter in 2020. Transportation costs were $2.42/boe for the nine months ended September 30, 2021, which represents a $0.10/boe or 4% decrease from the same period in 2020. This slight decrease in trucking costs for the three and nine months ended September 30, 2020 over the comparable periods in 2020 is due to reduced wait times at the various sales points to which oil is trucked.

Operating netback for the three and nine months ended September 30, 2021 were $33.14/boe and $34.34/boe respectively, 9% and 53% higher than the comparable quarters in 2020. This is mainly due to the 73% and 122% increase in the Company's combined average realized prices over the comparable periods, offset by the higher royalties and operating costs discussed above, and the $6.11/boe and $3.94/boe hedging losses respectively in the comparable three and nine month periods of 2021 (September 30, 2020 – gain of $5.51/boe for the three month period and gain of $6.37/boe for the nine month period).

Exploration and Evaluation

Exploration and evaluation expense generally consists of certain geological and geophysical costs, expiry of undeveloped lands, and costs of uneconomic exploratory wells. Exploration and evaluation expenses for the three months ended September 30, 2021 and 2020 were $12,686 and $12,275 respectively. For the nine months ended September 30, 2021 and 2020, exploration and evaluation expenses were $42,457 and $36,958 respectively.

Depletion and Depreciation

	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Depletion expense	**$ 1,005,453**	$ 1,118,119	**$ 2,976,208**	$ 3,487,177
Depreciation expense	**26,566**	28,606	**79,597**	85,403
Total	**$ 1,032,019**	$ 1,146,725	**$ 3,055,805**	$ 3,572,580
$ per boe	**$ 6.71**	$ 7.39	**$ 6.57**	$ 7.37

The depletion rate is calculated using the unit-of-production method on Proved and Probable oil and natural gas reserves, taking into account the future development costs ("FDC") to develop and produce undeveloped and non-producing reserves.

Depletion and depreciation expenses for the three months ended September 30, 2021 decreased to $6.71/boe from $7.39/boe for the same period in 2020. For the nine months ended September 30, 2021, depletion and depreciation expenses decreased to $6.57/boe from $7.37/boe for the same period in 2020. The decrease in depletion expense for the three and nine months ended September 30, 2021 over the comparable periods in 2020 is primarily due to amortization of production over a larger reserve base from the Company's December 31, 2020 independent engineer's evaluation report as prepared by McDaniel and Associates Consultants Ltd.

Impairment

At September 30, 2021 the Company performed an assessment of potential impairment indicators on each of its Cash Generating Units (CGUs), and management determined that no impairment or impairment reversal was required on its petroleum and natural gas assets (September 30, 2020 YTD - $3,859,110 impairment).

The recoverable amounts used were determined with fair value less costs to sell using a discounted cash flow method and categorized in Level 3 of the fair value hierarchy. Key assumptions in the determination of cash flows from reserves include crude oil and natural gas prices, royalties, operating costs, future development costs and discount rates specific to the underlying composition of assets residing in each CGU.

Capital Expenditures

	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Land and lease	**$ 83,875**	$ 1,812	**$ 91,054**	$ 10,286
Geological and geophysical	**168,959**	250,191	**490,774**	682,325
Drilling and completions	**1,790,096**	124,357	**2,110,773**	338,448
Facilities and infrastructure	**1,277,553**	15,839	**3,583,493**	36,314
Total capital expenditures(1)	**$ 3,320,483**	$ 392,199	**$ 6,276,094**	$ 1,067,373

Note:
(1) Total capital expenditures exclude decommissioning obligations and non-cash items.

The development capital spent during the nine months ended September 30, 2021 included spending for the polymer skid installation at the Company's Atlee G Pool, the acquisition and installation of a Free Water Knockout (FWKO) vessel, and the drilling of three new wells, as well as projects that intend to provide long-term operating costs savings and increase oil recovery.

General and Administrative

	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Gross general and administrative	**$ 852,867**	$ 732,655	**$ 2,600,551**	$ 2,012,107
Capitalized general and administrative	**(134,944)**	(177,755)	**(417,009)**	(525,142)
Total	**$ 717,923**	$ 554,900	**$ 2,183,542**	$ 1,486,965
$ per boe	**$ 4.67**	$ 3.58	**$ 4.69**	$ 3.07

General and administrative ("G&A") expenses increased on an absolute basis by 29% and 47% for the three and nine months ended September 30, 2021, and on a per boe basis $1.09/boe and $1.63/boe respectively over the comparable period in 2020. The G&A costs increased due to higher costs for legal, computer systems, OTC listing, investor relations, corporate re-branding, consulting fees, and staffing costs in the first nine months of 2021.

The Company capitalizes some general and administrative expenses which can be attributed to costs incurred during the period relating to its development and exploration activities. For the three and nine months ended September 30, 2021, capitalized general and administrative expenses decreased by 24% and 21% respectively over the comparable periods in 2020.

Finance Expense

	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Loan interest	**$ 372,189**	$ 701,282	**$ 1,434,395**	$ 2,340,978
Lease interest	**7,688**	9,837	**24,595**	29,967
Loss/(gain) in fair value of warrant liability	**(644,786)**	(31,551)	**4,536,175**	677,363
Loan transaction costs	**768,680**	-	**768,680**	-
Accretion of debt issuance costs	**18,297**	54,891	**128,079**	323,045
Amortization of deferred charges	**167,293**	48,792	**264,875**	208,165
Accretion of decommissioning liabilities	**25,592**	32,256	**76,776**	96,768
Total	**$ 714,953**	$ 815,507	**$ 7,233,575**	$ 3,676,286
$ per boe	**$ 4.65**	$ 5.26	**$ 15.55**	$ 7.59

Loan interest for the three and nine months ended 30, 2021 decreased by $329,093 and $906,583 over the respective periods in 2020 which is the result of a 46% reduction in the principle of the Term Loan/Credit Facility via repayments, combined with a decrease in interest rates for the quarter upon which the new Bank Credit Facility interest is calculated. The Company also recorded $7,688 and $24,595 for lease interest on right-of-use assets liability under IFRS 16. The finance expense per boe has decreased by 12% over the comparable three month period in 2020, due primarily to the aforementioned decrease in loan interest and a decrease in the warrant liability valuation, offset by an increase in term loan settlement costs incurred at payout of the previous term loan and opening of the new credit facility with ATB. The finance expense per boe has increased by 105% over the comparable nine month period in 2020 due primarily to an increase in the warrant liability valuation, and previously described fees relating to the pay out of the previous Term Loan and opening of new credit facilities, offset by lower interest expense as discussed above.

Accretion expense represents the adjusted present value of the Company's decommissioning obligations which include the abandonment and reclamation costs associated with wells and facilities. During the three and nine months ended September 30, 2021 accretion expense decreased by 21% over the comparable periods in 2020.

Remeasurement Loss/(Gain) on Warrant Liability

For the three and nine months ended September 30, 2021, the Company recognized a remeasurement gain of $644,786 and loss of $4,536,175, respectively ($31,551 gain and $677,363 loss for comparable periods in 2020[2]). The Company issued 13,750,000 warrants to a third-party lender on September 15, 2017 in conjunction with its term loan. Each warrant entitles the holder to purchase one common share of Hemisphere at an exercise price of $0.28 per share prior to September 15, 2022. The exercise price of the warrants represented a 40% premium to the 30-day volume weighted average price ("VWAP") of Hemisphere's common shares at market close on September 14, 2017. The warrants are subject to a forced exercise clause which applies upon a 30-day VWAP equaling or exceeding $1.40 per share. The warrants are non-transferable.

The warrants are classified as a financial liability as a result of a cashless exercise provision. In no event will the Company be required to settle the warrants through a cash payment. The fair value of the warrants is revalued every quarter using the Black and Scholes pricing model. Valuations for the current and previous quarter were calculated with the following inputs:

	September 30, 2021	December 31, 2020
Share Price	$ 0.84	$ 0.20
Risk-free interest rate	1.11%	0.39%
Expected life (years)	0.96	1.70
Expected volatility	78%	112%

Subsequent to the quarter end, the warrant holder has exercised 25% of the warrants on a cashless basis on October 25, 2021. This resulted in issuance of 2,299,851 shares for the cashless exercise of 3,437,500 warrants at the 30 day volume weighted average price of $0.846 per share. After the 25% exercise, the warrant holder has 10,312,500 warrants outstanding.

Tax Pools

The Company has approximately $60.2 million of tax pools available to be applied against future income for tax purposes. Based on available pools and current commodity prices, the Company does not expect

[2] *Prior period comparisons have been restated as outlined in note 3 in the March 31, 2021 quarterly financial statements.*

to pay current income tax in 2021 and any taxes payable beyond 2021 will primarily be a function of commodity prices, capital expenditures and production volumes.

	Deduction Rate		December 31, 2020
Canadian exploration expense (CEE)	100%	$	**3,336,823**
Canadian development expense (CDE)	30%		**19,655,797**
Canadian oil and gas property expense (COGPE)	10%		**4,438,962**
Non-capital losses carry forwards (NCL)	100%		**31,174,540**
Undepreciated capital cost (UCC)	20-55%		**811,977**
Share issuance costs and other	Various		**748,801**
Total		$	**60,166,900**

Summary of Quarterly Results

	2021			2020				2019
	Sep. 30 Q2[1]	Jun. 30 Q2[2]	Mar. 31 Q1[3]	Dec. 31 Q4[4]	Sep. 30 Q3[5]	Jun. 30 Q2[6]	Mar. 31 Q1[7]	Dec. 31 Q4[8]
Average daily production (boe/d)	**1,671**	1,786	1,654	1,522	1,686	1,645	1,973	2,166
Heavy oil and natural gas revenue	**10,431,678**	10,087,225	7,889,016	5,354,596	5,889,668	2,452,793	4,963,201	9,472,078
Operating field netback[9]	**6,032,734**	6,374,867	5,397,952	2,931,465	3,862,969	1,259,856	2,690,808	6,284,329
Cash provided by operating activities	**5,472,915**	4,741,719	3,202,500	2,127,640	3,087,951	816,755	3,357,353	3,519,506
Adjusted funds flow from operations[10]	**4,047,801**	4,230,423	4,041,562	2,380,051	3,406,612	1,353,680	2,154,594	4,324,443
Per share, basic and diluted	**0.05**	0.05	0.05	0.03	0.04	0.02	0.02	0.05
Net income (loss)[12]	**2,308,838**	(3,593,747)	1,767,336	(1,501,079)	1,473,572	(2,953,424)	1,210,299	(2,199,009)
Per share, basic and diluted	**0.03**	(0.04)	0.02	(0.02)	0.02	(0.04)	0.02	(0.03)
Combined average realized price ($/boe)	**67.87**	62.06	53.00	38.24	37.96	16.38	27.64	47.53
Operating netback ($/boe)[11]	**33.14**	34.32	35.59	25.43	30.41	17.74	19.63	30.70

Notes:

(1) The increases in revenue and adjusted funds flow from (used in) operations are due primarily to an increase in realized commodity prices.
(2) The increases in revenue, netbacks and adjusted funds flow from (used in) operations are due primarily to an increase in realized commodity prices.
(3) The increases in revenue, netbacks and adjusted funds flow from (used in) operations are due primarily to an increase in realized commodity prices.
(4) The decreases in revenue, netbacks and adjusted funds flow from (used in) operations are due primarily to a decrease in realized commodity prices and average production rates.
(5) The increases in revenue, netbacks and adjusted funds flow from (used in) operations are due primarily to an increase in realized commodity prices.
(6) The decreases in revenue, netbacks and adjusted funds flow from (used in) operations are due primarily to a decrease in realized commodity prices and average production rates.
(7) The decreases in revenue, netbacks and adjusted funds flow from (used in) operations are due primarily to a decrease in realized commodity prices.
(8) The increases in revenue, netbacks and adjusted funds flow from operations are due to increases in production rates and realized commodity prices.
(9) Operating field netback per boe is a non-IFRS measure calculated as the Company's oil and gas sales, less royalties, operating expenses and transportation costs on an absolute and per barrel of oil equivalent basis.
(10) Adjusted funds flow from operations is a non-IFRS measure that represents cash generated by operating activities, before changes in non-cash working capital and adjusted for any decommissioning expenditures, and may not be comparable to measures used by other companies.
(11) Operating netback is a non-IFRS measure calculated as the operating field netback plus the Company's realized commodity hedging gain (loss) on an absolute and per barrel of oil equivalent basis
(12) The net income (loss) has changed from prior presentation due to the recast of warrants from equity to debt, see note 3 of the quarterly financial statements

Outstanding Share Capital

	November 18, 2021	**September 30, 2021**	December 31, 2020
Fully diluted share capital			
Common shares issued and outstanding	90,634,653	**88,229,802**	86,782,302
Stock options	6,339,000	**6,444,000**	8,429,000
Warrants	10,312,500	**13,750,000**	13,750,000
Total fully diluted shares outstanding	107,286,153	**108,423,802**	108,961,302

On June 29, 2020, the Company announced the renewal of the normal course issuer bid (NCIB) to purchase and cancel, from time to time, up to 7,869,931 common shares of the Company until July 1, 2021. During the six months ended December 31, 2020, the Company purchased and cancelled 1,800,000 shares under the NCIB for $209,880 at an average cost of $0.12 per share. For the nine months ended June 30, 2021, the Company purchased and cancelled 537,500 shares under the NCIB for $164,070 at an average cost of $0.31 per share.

Further, on July 14, 2021 the Company announced the renewal of the normal course issuer bid (NCIB) to purchase and cancel, from time to time, up to 7,687,830 common shares of the Company until July 13, 2022. During the three months ended September 30, 2021, the Company has not repurchased any shares under the NCIB.

During the nine months ended September 30, 2021, the Company issued 1,985,000 shares for stock options exercised through the Employee Stock Option Plan, at an average exercise price of $0.10 per share.

Subsequent to the quarter end, the warrant holder has exercised 25% of the warrants on a cashless basis on October 5, 2021. This resulted in issuance of 2,299,851 shares for the cashless exercise of 3,437,500 warrants at the 30 day volume weighted average price of $0.846 per share. After the 25% exercise, the warrant holder has 10,312,500 warrants outstanding.

The Company has the following stock options that are outstanding and exercisable as at November 18, 2021:

Exercise Price	Grant Date	Expiry Date	Balance Outstanding November 18, 2021	Balance Exercisable November 18, 2021
$0.25	September 21, 2017	September 21, 2022	4,509,000	4,509,000
$0.28	October 2, 2017	October 2, 2022	150,000	150,000
$0.25	January 1, 2018	January 1, 2023	250,000	250,000
$0.12	March 1, 2019	March 1, 2024	50,000	50,000
$0.12	June 17, 2020	June 17, 2025	1,380,000	1,380,000
			6,339,000	6,339,000
Weighted-average exercise price			$0.22	$0.22

Liquidity and Capital Management

The Company's approach to managing liquidity risk is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when they become due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Company.

The Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Company utilizes authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures. The Company also attempts to match its payment cycle with collection of crude oil and natural gas revenues on the 25th of each month.

Management plans over the next two years to significantly lower debt while growing production and funds flow, which should allow the Company to accelerate internal projects, make strategic acquisitions, and increase return of capital to shareholders. For 2021, Hemisphere has set a capital program of approximately $6 million on polymer flood implementation, facilities upgrades, and a drilling program.

Management's forecasts may change materially based upon actual prices received, changes in future strip pricing, production volumes, operating costs, activity levels, cash flows, and the timing thereof and other factors which may or may not be within the control of the Company. The economic climate may lead to adverse changes in cash flow, working capital levels or debt balances, which may also have a direct impact on the Company's liquidity and ability to generate profits in the future.

a) Financing

The Company's net cash used in financing activities during the three and nine months ended September 30, 2021 was $6,195,706 and $9,671,356 ($3,457,059 and $5,565,263 cash used in financing activities for the three and nine months ended September 30, 2020). These funds are primarily a repayment in full of US$17,750,000 (CAD$22,471,500) of the Company's term loan and funding from the new bank debt of $16,233,591, as outlined below, plus shares purchased under the NCIB, and lease liability payments in the period.

b) Bank Debt

On July 28, 2021, the Company entered into a two year committed and extendible term facility with a Canadian Bank (the "Lender") providing for borrowings of up to $35,000,000 (the "Credit Facility"). As part of entering into the Credit Facility, the Company has fully repaid and terminated its former term loan with a third-party lender (see below).

The Credit Facility has an initial term date of May 31, 2022 (the "Term Date"), which is extendible at that time and on an annual basis for an additional 365 days upon request of the Company. The Credit Facility has a maturity date of May 31, 2023. If the term it is not extended on May 31, 2022, additional advances would not be permitted and any outstanding advances would become repayable at May 31, 2023. The Credit Facility is secured by a floating charge debenture and a general security agreement on the assets of the Company.

At September 30, 2021 the Company had drawn $16.2 million on the Credit Facility. There are standard reporting covenants under the Credit Facility and a financial covenant for the Company to maintain working capital above a ratio of 1.00 to 1.00. Working capital for the covenant is defined as current assets, less current liabilities, excluding fair value of financial instruments and warrant liability, plus the undrawn amount available under the credit facility. The Company was in compliance with these standard reporting covenants and the financial covenant with a working capital ratio of 6.55 to 1.00 as at September 30, 2021.

Under the Credit Facility, advances can be drawn as prime rate loans and bear interest at the bank's prime lending rate plus interest rates between 2.50% and 3.50%. Advances may also be drawn as guaranteed notes/banker's acceptances and letters of credit, subject to Canadian interest benchmark rates plus margins ranging from 3.50% to 4.50%. Standby fees are charged on the undrawn portion of the Credit Facility at rates ranging from 0.875% to 1.125%. These interest rates, fees and margins vary based on adjusted debt to earnings metrics determined at each quarter end for the preceding 12 months.

The semi-annual renewal of the available lending limit of the Credit Facility is scheduled for November 30, 2021 and is based on the Lenders' interpretation of the Company's reserves and future commodity prices. There can be no assurance that the amount or terms of the Credit Facility will not be adjusted at the next semi-annual review. In the event that the lender reduces the Credit Facility's borrowing base below the amount drawn at the time of the redetermination, the Company would have 45 days to eliminate any borrowing base shortfall by repaying the amount drawn in excess of the redetermined borrowing base. Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties.

c) Term Loan

On September 15, 2017, the Company entered into a first lien senior secured credit agreement (the "Credit Agreement") with a third-party lender (the "Lender") providing for a multi-draw, non-revolving term loan facility of a maximum aggregate principal amount of up to US$35.0 million. Security granted by the Company under the Credit Agreement included a demand debenture for US$75.0 million which provides for a first ranking security interest and floating and fixed charges over all of the real and personal property present and after acquired of the Company.

On July 28, 2021, the Company terminated this term loan with repayment of the full gross balance outstanding in the amount of US$17.75 million (CAD$22,471,500) from proceeds of the bank debt, as discussed above.

d) Capital Management

The Company manages its capital with the following objectives:

- Ensure sufficient flexibility to achieve the Company's ongoing business objectives including the replacement of production, funding of future growth opportunities, and pursuit of accretive acquisitions; and

- Maximize shareholder return through enhancing the Company's share value.

As part of its capital management process, the Company prepares budgets and forecasts, which are used by management and the Board of Directors to direct and monitor the strategy and ongoing operations and liquidity of the Company. Budgets and forecasts are subject to significant judgment and estimates relating to activity levels, future cash flows and the timing thereof and other factors which may or may not be within the control of the Company.

The Company monitors its capital structure and makes adjustments according to market conditions in an effort to meet its objectives given the current outlook of the business and industry in general. The capital structure of the Company is composed of shareholders' equity and the Term Loan. The Company may manage its capital structure by issuing new shares, repurchasing outstanding shares and issuing new debt instruments (see bank debt above), other financial or equity-based instruments, adjusting capital spending, or disposing of assets. The capital structure is reviewed on an ongoing basis.

Commitments

		2021	2022	2023	2024	2025	2026	2027	2028	Total
Office lease	$	16,575	66,300	27,625	-	-	-	-	-	110,500
Other leases		12,056	57,533	21,376	19,466	19,466	19,466	19,466	18,216	187,045
Equipment lease		58,674	352,043	352,043	352,043	352,043	352,043	352,043	293,369	2,464,301
	$	87,305	475,876	401,044	371,509	371,509	371,509	371,509	311,585	2,761,846

The above table includes future lease payments for polymer equipment based on the planned commencement date with the lessor for November 2021.

Off-Balance Sheet Arrangements

The Company has not entered into any off-balance sheet transactions.

Related Party Transactions

Compensation to key executive personnel, consisting of the Company's officers, directors and Chairman, was paid as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Salaries and wages	**$ 304,500**	$ 289,001	**$ 881,000**	$ 855,000
Share-based payments	**-**	-	**-**	80,462

Proposed Transactions

As of the effective date, there are no outstanding proposed transactions.

Changes in Accounting Policies

As of the effective date, there are no changes in accounting policies.

Risks

The Company's activities expose it to a variety of risks that arise as a result of its exploration, development, production and financing activities. These risks and uncertainties include, among other things, volatility in market prices for oil and natural gas, general economic conditions in Canada, the US and globally and other factors described under Risk Factors in Hemisphere's most recently filed Annual Information Form which is available on the Company's website at www.hemisphereenergy.ca or on SEDAR at www.sedar.com. Readers are cautioned that this list of risk factors should not be construed as exhaustive.

The following provides information about the Company's exposure to some risks associated with the oil and gas industry, as well as the Company's objectives, policies and processes for measuring and managing risk.

Business Risk

Oil and gas exploration and development involves a high degree of risk whereby many properties are ultimately not developed to a producing stage. There can be no assurance that the Company's future exploration and development activities will result in discoveries of commercial bodies of oil and gas. Whether an oil and gas property will be commercially viable depends on a number of factors including the particular attributes of the reserve and its proximity to infrastructure, as well as commodity prices and government regulations, including regulations relating to prices, taxes, royalties, land tenure, land use, and environmental protection. The exact effect of these factors cannot be accurately predicted, and the combination of these factors may result in an oil and gas property not being profitable.

Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its payment obligations. This risk arises principally from the Company's receivables from joint operators and oil and natural gas marketers, and reclamation deposits. The credit risk associated with reclamation deposits is minimized substantially by ensuring this financial asset is placed with major financial institutions with strong investment-grade ratings by a primary ratings agency. The credit risk associated with accounts receivable is mitigated as the Company monitors monthly balances to limit the risk associated with collections. The Company does not anticipate any default. There are no balances over 90 days past due or impaired.

The maximum exposure to credit risk is as follows:

	September 30, 2021	December 31, 2020
Accounts receivable		
Marketing receivables	**$ 2,851,856**	$ 1,767,578
Trade receivables	**131,701**	159,776
Receivables from joint ventures	**35,239**	5,309
Reclamation deposits	**115,535**	115,535
	$ 3,134,331	$ 2,048,198

The Company sells the majority of its oil production to two major oil marketers and, therefore, is subject to concentration risk which is mitigated by management's policies and practices related to credit risk, as discussed above. Historically, the Company has never experienced any collection issues with its oil marketer.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's approach to managing liquidity risk is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when they become due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Company.

The Company also prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Company utilizes authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures. The Company will also attempt to match its payment cycle with collection of crude oil and natural gas revenues on the 25th of each month.

In light of the current volatility in oil and gas prices and uncertainty regarding the timing for recovery in such prices as well as pipeline and transportation capacity constraints, management's ability to prepare financial forecasts is challenging. The economic climate may lead to adverse changes in cash flow, working capital levels or debt balances, which may also have a direct impact on the Company's liquidity and ability to generate profits in the future.

At September 30, 2021, the Company had net debt (a non-IFRS measure calculated as current assets, less current liabilities excluding fair value of financial instruments, lease and warrant liabilities, and including the bank debt) of $18,231,440 (December 31, 2020 - $24,429,190). The Company funds its operations through operating cash flows and a committed $35MM two year renewable term credit facility at ATB Financial.

Market risk

Market risk is the risk that changes in market prices, such as, foreign exchange rates, commodity prices, and interest rates will affect the value of the financial instruments. Market risk is comprised of interest rate risk, foreign currency risk, commodity price risk, and other price risk.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. Borrowings under the Company's Term Loan are subject to variable interest rates. A one percent change in interest rates would have a $160,000 annual effect on net income.

Foreign currency risk

The Company's functional and reporting currency is the Canadian dollar. The Company does not sell or transact in any foreign currency; except; i) the Company's commodity prices are largely denominated in United States dollars ("USD"), and as a result, the prices that the Company receives are affected by fluctuations in the exchange rates between the USD and the Canadian dollar. The exchange rate effect cannot be quantified, but generally an increase in the value of the Canadian dollar compared to the USD will reduce the prices received by the Company for its crude oil and natural gas sales; ii) the Company's Term Loan was denominated in USD, and as result, the amount that the Company was obligated to repay when the company agreed to terminate the term was affected by fluctuations in the exchange rate between the USD and the Canadian dollar at that time. A 100 basis points change in the foreign exchange rate would have a $294,000 effect on derivative contracts and the annual net loss.

Commodity price risk

Commodity prices for petroleum and natural gas are impacted by global economic events that dictate the levels of supply and demand, as well as the relationship between the Canadian dollar and the USD. Significant changes in commodity prices may materially impact the Company's adjusted funds flow from operations, and ability to raise capital. The Company has derivative commodity contracts in place as further disclosed within this MD&A.

Other price risk

Other price risk is the risk that the fair or future cash flows of a financial instrument will fluctuate due to changes in market prices, other than those arising from interest rate risk, foreign currency risk or commodity price risk. The Company is not exposed to significant other price risk.

COVID-19 Risk

In March 2020, the World Health Organization declared a global pandemic following the emergence and rapid spread of a novel strain of the coronavirus ("COVID-19"). The outbreak and subsequent measures enforced to limit the spread of the pandemic contributed to volatility in financial markets. The pandemic has adversely impacted global commercial activity, including significantly reducing worldwide demand for crude oil and natural gas. Global oil demand has since improved steadily in the latter half of 2020 and first half of 2021 as economies began to reopen and governments approved the rollout of COVID-19 vaccines.

The West Texas Intermediate ("WTI") benchmark price increased in the third quarter of 2021, averaging 7% higher than the second quarter of 2021, and 64% higher than the comparative nine months of 2020. Although government authorities have eased COVID-19 restrictions and global economies are improving, there is no certainty when demand levels will return to pre-COVID levels and therefore the situation remains dynamic. The ultimate duration and magnitude of the impact on the economy and financial effect on the Company is not known at this time; however, Hemisphere is optimistic that the worst is behind us and economic conditions will continue to improve.

Non-IFRS Measures

This document contains the terms adjusted funds flow from operations, operating netback, operating field netback and net debt which are not recognized measures under IFRS and may not be comparable to similar measures presented by other companies.

a) The Company considers adjusted funds flow from operations to be a key measure that indicates the Company's ability to generate the funds necessary to support future growth through capital investment and to repay any debt. Adjusted funds flow from operations is a measure that represents cash generated by operating activities, before changes in non-cash working capital and adjusted for decommissioning expenditures, and may not be comparable to measures used by other companies. Adjusted funds flow from operations per share is calculated using the same weighted-average number of shares outstanding as in the case of the earnings per share calculation for the period.

   A reconciliation of adjusted funds flow from operations to cash provided by operating activities is presented as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Cash provided by operating activities	**$ 5,472,918**	$ 3,087,951	**$ 13,417,137**	$ 7,262,068
Change in non-cash working capital	**(1,425,113)**	316,958	**(1,134,847)**	(460,451)
Adjust: Decommissioning obligation expenditures	-	1,704	**37,501**	113,270
Adjusted funds flow from operations	**$ 4,047,805**	$ 3,406,613	**$ 12,319,791**	$ 6,914,887
Per share, basic	**$ 0.05**	$ 0.04	**$ 0.14**	$ 0.08
Per share, diluted	**$ 0.04**	$ 0.04	**$ 0.13**	$ 0.08

b) Operating field netback is a benchmark used in the oil and natural gas industry and a key indicator of profitability relative to current commodity prices. Operating field netback is calculated as oil and gas sales, less royalties, operating expenses and transportation costs on an absolute and per barrel of oil equivalent basis. These terms should not be considered an alternative to, or more meaningful than, cash flow from operating activities or net income or loss as determined in accordance with IFRS as an indicator of the Company's performance.

c) Operating netback is a non-IFRS measure calculated as the operating field netback plus the Company's realized commodity hedging gain (loss) on an absolute and per barrel of oil equivalent basis.

d) Net debt is closely monitored by the Company to ensure that its capital structure is maintained by a strong balance sheet to fund the future growth of the Company. Net debt is used in this document in the context of liquidity and is calculated as the total of the Company's current assets, less current liabilities, excluding the fair value of financial instruments, lease and warrant liabilities, and including the bank debt or gross term loan. There is no IFRS measure that is reasonably comparable to net debt.

The following table outlines the Company calculation of net debt:

	As at	
	September 30, 2021	December 31, 2020
Current assets[(1)]	$ **3,823,013**	$ 3,001,610
Current liabilities[(1)]	**(5,820,862)**	(1,334,300)
Bank Loan or Gross term loan[(2)]	**(16,233,591)**	(26,096,500)
Net debt	$ **(18,231,440)**	$ (24,429,190)

Note:

(1) Excluding fair value of financial instruments and lease and warrant liabilities.

(2) Gross term loan is calculated as the total USD draws on the term loan translated to Canadian Dollars at the period end exchange rate.

Boe Conversion

Within this document, petroleum and natural gas volumes and reserves are converted to a common unit of measure, referred to as a barrel of oil equivalent (boe), using a ratio of 6,000 cubic feet of natural gas to one barrel of oil. Use of the term boe may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalent method and does not necessarily represent a value equivalency at the wellhead.

Forward-Looking Statements

In the interest of providing Hemisphere's shareholders and potential investors with information regarding the Company, including management's assessment of the future plans and operations of Hemisphere, certain statements contained in this MD&A (particularly the Message to Shareholders) constitute forward-looking statements or information (collectively forward-looking statements) within the meaning of applicable securities legislation. Forward-looking statements are typically identified by words such as anticipate, continue, estimate, expect, forecast, may, will, project, could, plan, intend, should, believe, outlook, potential, target and similar words suggesting future events or future performance. In particular, but without limiting the foregoing, this document (particularly the Message to Shareholders) contains forward-looking statements pertaining to the following: management's plans over the next two years to significantly lower debt while growing production and funds flow, which should allow the Company to accelerate internal projects, make strategic acquisitions, and increase return of capital to shareholders, Hemisphere' capital program and the manner it intends to spend such funds; future oil and natural gas prices; future operational activities; and plans for continued growth in the Company's production, reserves and cash flow; the compliance of the Company under its credit agreements, and the expectation for the increasing of the Company's asset base with continued successful waterflood operations. In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and can be profitably produced in the future.

With respect to forward-looking statements contained in this MD&A, the Company has made assumptions regarding, among other things: future capital expenditure levels; future oil and natural gas prices and differentials between light, medium and heavy oil prices; results from operations including future oil and natural gas production levels; future exchange rates and interest rates; Hemisphere's ability to obtain equipment in a timely manner to carry out development activities; Hemisphere's ability to market its oil and natural gas successfully to current and new customers; the impact of increasing competition; Hemisphere's ability to obtain financing on acceptable terms; the continued availability of Hemisphere's credit facility; the effects of COVID-19 on Hemisphere's operations (including those affecting its partners and service providers); and Hemisphere's ability to add production and reserves through our development and exploitation activities.

Although Hemisphere believes that the expectations reflected in the forward-looking statements contained in this MD&A, and the assumptions on which such forward-looking statements are made, are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned not to place undue reliance on forward-looking statements included in this MD&A, as there can be no assurance that the plans, intentions or expectations upon which the forward-looking statements are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause Hemisphere'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 following: volatility in market prices for oil and natural gas; the effects of COVID-19, risks associated with Hemisphere's enhanced oil recovery operations, including effects on its reserves, reservoirs and production; general economic conditions in Canada, the U.S. and globally; and the other factors described under "Risk Factors" in Hemisphere's most recently filed Annual Information Form available on the Company's website at www.hemisphereenergy.ca or on SEDAR at www.sedar.com. Readers are cautioned that this list of risk factors should not be construed as exhaustive.*

The forward-looking statements contained in this MD&A speak only as of the date of this document. Except as expressly required by applicable securities laws, Hemisphere 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 MD&A are expressly qualified by this cautionary statement.