Q3 2019

Hemisphere energy corporation

TSX-V: HME
www.hemisphereenergy.ca

Q3 2019 HIGHLIGHTS

- Achieved record revenue of $8.2 million, a 40% increase over the third quarter of 2018.
- Realized record quarterly funds flow from operations of $3.6 million, a 157% increase over the third quarter of 2018.
- Increased average quarterly production to a record 1,738 boe/d (96% oil), a 51% increase as compared to the third quarter of 2018.
- Increased operating netback by 31% to $30.64/boe, as compared to the third quarter of 2018.
- Reduced operating and transportation costs by 13% to $11.82/boe, as compared to the third quarter of 2018.
- Reduced net general and administration costs by 18% to $3.02/boe, as compared to the third quarter of 2018.
- Completed an 11 well drilling program and facility upgrades with $6.4 million in capital expenditures.
- Repurchased and canceled 475,000 shares under the Company's Normal Course Issuer Bid ("NCIB").
- Increased Hemisphere's corporate Liability Management Ratio (LMR) with the Alberta Energy Regulator to 9.77 as of September 2019.

CORPORATE UPDATE

Hemisphere delivered both financial and operational success during the third quarter of 2019 as the Company completed its summer development program with $6.4 million in capital expenditures. The drilling program included 11 new wells in the Atlee Buffalo G pool that were placed on production through the third quarter with results exceeding internal expectations. Corporate production in October 2019 averaged approximately 2,200 boe/d, an increase of more than 25% over Hemisphere's third quarter average production rate. The Company also invested in facilities, infrastructure, and pipelines to handle additional production from the drilling program.

Hemisphere achieved a solid financial quarter with record revenue of $8.2 million and record funds flow from operations of $3.6 million. Despite a lower oil price environment the Company's operating netback was $30.64/boe, which is largely due to low operating and transportation costs of $11.82/boe. Through the quarter, Hemisphere continued to decrease its per barrel corporate costs and brought its general and administration costs down to $3.02/boe.

Over the past two years Hemisphere has executed a low risk growth plan through development of its oil assets in the Atlee Buffalo area of southeast Alberta. Management has consistently delivered production and reserve growth with efficient operations through times of significant volatility in commodity prices. This has positioned Hemisphere to focus on deleveraging while continuing to develop its asset base.

Hemisphere intends to keep its capital expenditures within corporate cash flow with additional funds anticipated to be used to pay down debt and purchase shares under Hemisphere's previously announced NCIB. The Company has acquired and canceled 729,500 shares to date under the NCIB and is now in a position to focus on improving its debt metrics, while continuing to optimize new production, further reduce per barrel operating and corporate costs, and move forward its 2020 development program.

Q3 2019 FINANCIAL AND OPERATING HIGHLIGHTS

	Three Months Ended September 30		Nine Months Ended September 30	
	2019	2018	**2019**	2018
OPERATING				
Average daily production				
Oil (bbl/d)	**1,670**	1,106	**1,440**	977
Natural gas (Mcf/d)	**404**	255	**329**	257
NGL (bbl/d)	**1**	1	**1**	2
Combined (boe/d)	**1,738**	1,150	**1,496**	1,021
Oil and NGL weighting	**96%**	96%	**96%**	96%
Average sales prices				
Oil ($/bbl)	**$ 53.21**	$ 57.19	**$ 55.63**	$ 55.26
Natural gas ($/Mcf)	**0.80**	1.31	**1.74**	1.55
NGL ($/bbl)	**55.62**	56.07	**43.79**	57.55
Combined ($/boe)	**$ 51.34**	$ 55.36	**$ 53.96**	$ 53.33
Operating netback ($/boe)				
Petroleum and natural gas revenue	**$ 51.34**	$ 55.36	**$ 53.96**	$ 53.33
Royalties	**6.95**	11.22	**7.07**	9.67
Operating costs	**9.37**	11.06	**10.51**	12.17
Transportation costs	**2.45**	2.47	**2.49**	2.67
Operating field netback(1)	**32.57**	30.62	**33.88**	28.83
Realized commodity hedging loss	**1.93**	7.19	**3.03**	8.15
Operating netback(2)	$ **30.64**	$ 23.43	**$ 30.85**	$ 20.67
FINANCIAL				
Petroleum and natural gas revenue	**$ 8,207,658**	$ 5,856,762	**$ 22,039,005**	$ 14,869,598
Operating field netback(1)	**5,206,704**	3,239,216	**13,838,732**	8,037,033
Operating netback(2)	**4,898,805**	2,478,636	**12,600,470**	5,763,569
Cash flow provided by operating activities	**3,803,907**	2,192,827	**6,966,814**	1,998,995
Funds flow from operations(3)	**3,558,673**	1,387,469	**8,753,556**	2,738,280
Per share, basic and diluted	**0.04**	0.02	**0.10**	0.03
Net income (loss)	**2,854,615**	(236,344)	**4,777,972**	(4,878,900)
Per share, basic and diluted	**0.03**	(0.00)	**0.05**	(0.05)
Capital expenditures	**6,386,377**	9,185,090	**9,978,618**	14,588,032
Net debt(4)	**35,934,983**	31,207,369	**35,934,983**	31,207,369
Gross term Loan(5)	**$ 34,426,600**	$ 28,241,400	**$ 34,426,600**	$ 28,241,400

Notes:

(1) 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.

(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) Funds flow from operations is a non-IFRS measure that represents cash generated by operating activities, before changes in non-cash working capital 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 including term loan or bank indebtedness and excluding fair value of financial instruments.

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

	Nine months ended September 30	
	2019	2018
SHARE CAPITAL		
Common shares outstanding	**89,408,302**	89,793,302
Stock options outstanding	**8,184,000**	8,419,000
Warrants outstanding	**13,750,000**	13,750,000
Fully Diluted	**111,342,302**	111,962,302
Weighted-average shares outstanding – basic	**89,820,390**	89,793,302
Weighted-average shares outstanding –diluted	**90,520,664**	89,793,302

MANAGEMENT'S DISCUSSION AND ANALYSIS

Dated as at November 13, 2019

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, 2019 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, 2019, and the audited annual financial statements and related notes for the year ended December 31, 2018. 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

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".

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 northeast of Brooks in southeastern Alberta. Hemisphere has a 100% working interest in 15,680 net acres and has been building a land position in Atlee Buffalo through Crown land sales and strategic acquisitions.

Jenner, Alberta

Hemisphere owns and operates all of its wells and has a land position of 9,624 net acres in the Jenner area. The property is accessible year-round and is located 30 kilometers west of the Company's Atlee Buffalo property in southeastern Alberta.

Operating Results

The Company generated funds flow from operations of $3,558,673 ($0.04/share) during the third quarter of 2019, as compared to funds flow from operations of $1,387,469 ($0.02/share) during the third quarter of 2018. Funds flow for the nine months ended September 30, 2019 increased to

$8,753,556 ($0.10/share) from $2,738,280 ($0.03/share) for the same period in 2018. The increase in funds flow from operations for three and nine months ended September 30, 2019 are primarily from the increases in production of 51% and 46% over the comparable three and nine months in 2018 respectively.

For the three and nine months ended September 30, 2019, the Company reported net income of $2,854,615 ($0.03/share) and $4,777,972 ($0.05/share), respectively, compared to net losses of $236,344 ($0.00/share) and $4,878,900 ($0.05/share) for the three and nine months ended September 30, 2018, respectively. The higher net income of $9,656,872 during the comparable nine months ended September 30, 2018 is primarily attributed to the increase in operating field netback of $5,801,700, with reduced hedging losses and foreign exchange losses, in the amounts of $3,526,025and $2,054,016 respectively.

Production

	Three Months Ended September 30		Nine Months Ended September 30	
By product:	**2019**	2018	**2019**	2018
Oil (bbl/d)	**1,670**	1,106	**1,440**	977
Natural gas (Mcf/d)	**404**	255	**329**	257
NGL (bbl/d)	**1**	1	**1**	2
Total (boe/d)	**1,738**	1,150	**1,496**	1,021
Oil and NGL weighting	**96%**	96%	**96%**	96%

In the third quarter of 2019, the Company's average daily production was 1,738 boe/d (96% oil and NGL) representing a 51% increase from 1,150 boe/d over the comparable quarter in 2018. For the nine months ended September 30, 2019, the Company's average daily production was 1,496 boe/d (96% oil and NGL), representing a 46% increase from 1,021 boe/d for the same period in 2018. This increase in production can be attributed to 11 new wells drilled and placed on production within the third quarter of 2019, as well as the continued success and improvement of the base waterflood performance in the Upper Mannville F and G pools.

Average Benchmark and Realized Prices

	Three Months Ended September 30		Nine Months Ended September 30	
	2019	2018	**2019**	2018
Benchmark prices				
WTI ($US/bbl)[1]	**$ 56.47**	$ 69.46	**$ 57.04**	$ 66.74
Exchange rate (1 $US/$C)	**1.3205**	1.3070	**1.3291**	1.2872
WTI ($C/bbl)	**74.57**	90.79	**75.81**	85.90
WCS Diff ($C/bbl)	**16.19**	29.01	**15.55**	28.12
WCS ($C/bbl)[2]	**58.38**	61.78	**60.26**	57.78
AECO natural gas ($US/Mcf)[3]	**1.00**	1.28	**1.57**	1.51
Average realized prices				
Crude oil ($C/bbl)	**53.21**	57.19	**55.63**	55.26
Natural gas ($C/Mcf)	**0.80**	1.31	**1.74**	1.55
NGL ($C/bbl)	**55.62**	56.07	**43.79**	57.55
Combined ($C/boe)	**$ 51.34**	$ 55.36	**$ 53.96**	$ 53.33

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 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 decreased by 7% from $55.36/boe during the three months ended September 30, 2018 to $51.34/boe during three months ended September 30, 2019. This decrease is the result of lower oil prices during the three months ended September 30, 2019, reflected in the $3.98/bbl decrease in the Company's average realized crude oil price over the same period in 2018. The Company's combined average realized price increased by 1% from $53.33/boe during the nine months ended September 30, 2018 to $53.96/boe during nine months ended September 30, 2019. The increase for the nine month period is the result of slightly higher oil prices during the nine months ended September 30, 2019 which are reflected in the $0.37/bbl increase from the Company's average realized crude oil price during the same period in 2018.

The Company's average realized natural gas price decreased in the three months ended September 30, 2019 by $0.51/Mcf over the comparable period in 2018. For the nine months ended September 30, 2019 the Company's average realized natural gas price increased by 13% to $1.74 from $1.55 in the comparable nine month period of 2018.

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	250 bbl/d	US$50.67	WTI-NYMEX	January 1, 2019 – December 31, 2019
Crude oil	Collar	130 bbl/d	US$40.00-US$74.50	WTI-NYMEX	March 1, 2019 – December 31, 2019
Crude oil	Collar	100 bbl/d	US$55.00-US$66.00	WTI-NYMEX	April 1, 2019 – December 31, 2019
Crude oil	Collar	100 bbl/d	US$58.00-US$66.15	WTI-NYMEX	June 1, 2019 – December 31, 2019
Crude oil	Swap	200 bbl/d	US$50.67	WTI-NYMEX	January 1, 2020 – August 31, 2020
Crude oil	Collar	120 bbl/d	US$40.00-US$68.25	WTI-NYMEX	January 1, 2020 – December 31, 2020
Crude oil	Collar	200 bbl/d	US$40.00-US$67.05	WTI-NYMEX	September 1, 2020 – December 31, 2020
Crude oil	Collar	275 bbl/d	US$40.00-US$65.50	WTI-NYMEX	January 1, 2021 – March 31, 2021

At September 30, 2019 the commodity contracts were fair valued as an asset of $32,919 recorded on the balance sheet, an unrealized gain for the three month period of $875,506 and an unrealized loss for the nine month period of $823,057 respectively (September 30, 2018 – loss of $721,244 and $3,313,880 respectively).

Revenue

		Three Months Ended September 30				Nine Months Ended September 30		
		2019		2018		**2019**		2018
Oil	**$**	**8,174,202**	$	5,820,348	**$**	**21,868,981**	$	14,737,045
Natural gas		**29,746**		30,662		**156,575**		108,471
NGL		**3,710**		5,752		**13,449**		24,082
Total	**$**	**8,207,658**	$	5,856,762	**$**	**22,039,005**	$	14,869,598

Revenue for the three and nine months ended September 30, 2019 increased by 40% and 48%, respectively, from the comparable periods in 2018. These increases are attributed to increases in production by 51% and 46% respectively during the periods over the comparable periods in 2018.

Operating Netback

	Three Months Ended September 30		Nine Months Ended September 30	
	2019	2018	**2019**	2018
Operating netback				
Revenue	**$ 8,207,658**	$ 5,856,762	**$ 22,039,005**	$ 14,869.598
Royalties	**1,111,091**	1,186,777	**2,887,747**	2,696,740
Operating costs	**1,497,806**	1,169,758	**4,294,097**	3,392,242
Transportation costs	**392,057**	261,011	**1,018,429**	743,583
Operating field netback[1]	**$ 5,206,704**	$ 3,239,216	**$ 13,838,732**	$ 8,037,033
Realized commodity hedging loss	**307,899**	760,580	**1,238,262**	2,273,464
Operating netback[2]	**$ 4,898,805**	$ 2,478,636	**$ 12,600,470**	$ 5,763,569
Operating netback ($/boe)				
Revenue	**$ 51.34**	$ 55.36	**$ 53.96**	$ 53.33
Royalties	**6.95**	11.22	**7.07**	9.67
Operating costs	**9.37**	11.06	**10.51**	12.17
Transportation costs	**2.45**	2.47	**2.49**	2.67
Operating field netback[1]	**$ 32.57**	$ 30.62	**$ 33.88**	$ 28.83
Realized commodity hedging loss	**1.93**	7.19	**3.03**	8.15
Operating Netback[2]	**$ 30.64**	$ 23.43	**$ 30.85**	$ 20.67

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 for the three months ended September 30, 2019 were $6.95/boe, representing a 38% decrease from the three months ended September 30, 2018. Royalties for the nine months ended September 30, 2019 were $7.07/boe, representing an 27% decrease from the same period in 2018. This was primarily the result of Hemisphere's newly drilled 2019 wells being on royalty holiday.

Operating costs include all costs for gathering, processing, dehydration, compression, water processing and marketing of the oil, natural gas and NGLs, as well as additional costs incurred periodically for maintenance and repairs. Operating costs for the three and nine months ended September 30, 2019 increased on an absolute basis by 28% and 27% respectively, but decreased on a per boe basis by $1.69 and $1.65, representing a 15% and 14% decrease respectively over the comparable periods in 2018. The notable increase to absolute operating costs in the three and nine month periods is the result of more operating wellbores and corresponding production, coupled with a higher volume of well workovers required during the period. The decrease in per boe costs for the three and nine month period is due to more stable fixed operating costs and efficiencies from the higher production.

Transportation costs include all costs incurred to transport emulsion and oil and gas sales to processing and distribution facilities. Transportation costs were $2.45/boe during the third quarter of 2019, which is a $0.02/boe decrease from the comparable quarter in 2018. Transportation costs were $2.49/boe for the nine months ended September 30, 2019, which represents a $0.18/boe decrease from the same period in 2018. The Company's installation of water handling facilities in 2018 led to a reduction in trucked emulsion, resulting in a decrease in trucking for the three and nine months ended September 30, 2019 over the comparable periods in 2018.

Operating netback for the three and nine months ended September 30, 2019 were $30.64/boe and $30.85/boe respectively, 31% and 49% higher than the comparable periods in 2018. This is mainly due to lower royalties and operating expenses, as well as lower hedging losses during the three and nine month periods as discussed above.

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, 2019 and 2018 were $15,441 and $10,533, respectively. For the nine months ended September 30, 2019 and 2018, exploration and evaluation expenses were $52,929 and $36,074, respectively.

Depletion and Depreciation

	Three Months Ended September 30		Nine Months Ended September 30	
	2019	2018	**2019**	2018
Depletion expense	**$ 1,617,171**	$ 1,297,111	**$ 4,078,315**	$ 3,186,452
Depreciation expense	**28,356**	1,371	**81,516**	4,110
Total	**$ 1,645,527**	$ 1,298,482	**$ 4,159,831**	$ 3,190,562
$ per boe	**$ 10.29**	$ 12.27	**$ 10.18**	$ 11.44

The Company depletes its property, plant and equipment 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. The Company depreciates its right-of-use (ROU) assets on a straight-line basis.

Depletion and depreciation expenses for the three months ended September 30, 2019 decreased to $10.29/boe from $12.27/boe for the same period in 2018. For the nine months ended September 30, 2019, depletion and depreciation expenses decreased to $10.18/boe from $11.44/boe for the same period in 2018. The decrease in depletion expense for the three and nine months ended September 30, 2019 over the comparable periods in 2018 is primarily due to amortization of production over a larger reserve base from the Company's December 31, 2018 independent engineer's evaluation report as prepared by McDaniel and Associates Consultants Ltd.

Capital Expenditures

	Three Months Ended September 30		Nine Months Ended September 30	
	2019	2018	**2019**	2018
Land and lease	**$ 82,923**	$ 18,185	**$ 110,646**	$ 23,215
Geological and geophysical	**16,625**	28,153	**323,921**	272,355
Drilling and completions	**4,981,297**	6,611,383	**7,486,378**	10,877,600
Facilities and infrastructure	**1,305,533**	2,527,370	**2,057,674**	3,414,862
Total capital expenditures(1)	**$ 6,386,377**	$ 9,185,090	**$ 9,978,618**	$ 14,588,032

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

The development capital spent during the first nine months of 2019 included an eleven well drill program, expansion of the G pool battery, preparatory spending for a 2020 drilling program and the upsizing of pumps at several wells.

General and Administrative

	Three Months Ended September 30		Nine Months Ended September 30	
	2019	2018	**2019**	2018
Gross general and administrative	**$ 604,124**	$ 563,987	**$ 1,645,764**	$ 1,688,158
Capitalized general and administrative	**(121,055)**	(186,886)	**(454,594)**	(414,546)
Total	**$ 483,070**	$ 377,101	**$ 1,191,170**	$ 1,273,612
$ per boe	**$ 3.02**	$ 3.56	**$ 2.92**	$ 4.57

General and administrative ("G&A") expenses increased by $105,967 for the three months and decreased by $82,442 for the nine months ended September 30, 2019 over the comparable periods in 2018. The G&A expense reductions over the nine months are from the combination of lower gross expenses due to reduced office rent and corporate costs, and higher capitalized costs from the drilling program. In addition, the gross general and administrative expenses are further reduced with the adoption of IFRS 16 "Leases," on January 1, 2019, as discussed in the Changes in Accounting Policies section of this MD&A.

On a per boe basis, the G&A expenses reduced significantly by $0.54/boe and $1.65/boe for the three and nine months ended September 30, 2019 respectively, from the comparable periods in 2018. This is from the expense reductions discussed above, with the additional impact of the increase in production.

The Company capitalizes some general and administrative expenses which can be attributed to any costs incurred during the period relating to its development and exploration activities. For the three and nine months ended September 30, 2019, capitalized general and administrative expenses decreased by $65,832 and increased by $40,048 over the respective comparable periods in 2018.

Share-based Payments

Share-based payments are non-cash expenses which reflect the estimated value of stock options issued to directors, employees and consultants of the Company.

In March of 2019 the Company granted 50,000 stock options to a consultant at an exercise price of $0.12 each, all of which vested immediately. The Company uses a Black-Scholes option pricing model to calculate the fair value of stock option grants where the corresponding expense is recognized over the option vesting period. The total valuation of the vested options from grants in the nine months ended September 30, 2019, was $179,945, of which $117,079 was expensed as stock-based compensation and $62,866 was capitalized in prior quarters of 2019.

	Three Months Ended September 30		Nine Months Ended September 30	
	2019	2018	**2019**	2018
Share-based payments	**$ -**	$ 56,854	**$ 117,079**	$ 174,952
Capitalized costs	**-**	31,433	**62,866**	101,613
Total share-based payments	**$ -**	$ 88,287	**$ 179,945**	$ 276,565

Finance Expense

	Three Months Ended September 30		Nine Months Ended September 30	
	2019	2018	**2019**	2018
Loan interest	**$ 857,710**	$ 707,182	**$ 2,620,745**	$ 1,789,708
Lease interest	**11,039**	-	**34,518**	-
Accretion of debt issuance costs	**86,908**	51,625	**199,972**	148,815
Amortization of deferred charges	**64,216**	76,129	**179,499**	225,094
Accretion of decommissioning liabilities	**37,233**	34,587	**111,699**	103,759
Total	**$ 1,057,107**	$ 869,523	**$ 3,146,433**	$ 2,267,376
$ per boe	**$ 6.61**	$ 8.22	**$ 7.70**	$ 8.13

Loan Interest for the three and nine months ended September 30, 2019 increased by $150,527 and $831,035 over the respective periods in 2018. The increases in absolute values of Finance Expenses are primarily a result of the higher carrying balance of the term loan in 2019 over the comparable periods in 2018. The relative finance expense per boe has decreased by 20% and 5% respectively over the comparable periods in 2018. This per boe decrease is due to the marginal increase in absolute costs being assessed over a much larger production base in the three and nine months ended September 30, 2019. The Company also recorded lease interest of $11,039 and $34,518 on right-of-use assets liability under the new IFRS 16 accounting policy.

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, 2019 accretion expense increased by 8% over the comparable periods in 2018 due to the additional abandonment and reclamation costs recorded for the new wells drilled.

Tax Pools

The Company has approximately $70 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 to pay current income tax in 2019 and any taxes payable beyond 2019 will primarily be a function of commodity prices, capital expenditures and production volumes.

	Deduction Rate	**December 31, 2018**
Canadian exploration expense (CEE)	100%	**$ 3,336,823**
Canadian development expense (CDE)	30%	**21,995,676**
Canadian oil and gas property expense (COGPE)	10%	**5,480,200**
Non-capital losses carry forwards (NCL)	100%	**36,314,261**
Undepreciated capital cost (UCC)	20-55%	**896,082**
Share issuance costs and other	Various	**1,465,252**
Total		**$ 69,488,294**

Summary of Quarterly Results

	2019			2018				2017
	Sep. 30 Q3(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)	**1,738**	1,367	1,379	1,378	1,150	1,053	858	770
Oil and natural gas revenue	**8,207,658**	7,396,095	6,435,252	2,886,840	5,856,762	5,618,915	3,393,921	3,528,565
Operating field netback(9)	**5,206,705**	4,357,767	4,274,261	1,023,282	3,239,217	3,279,840	1,517,979	1,650,446
Cash provided by (used in) operating activities	**3,803,907**	2,536,247	626,659	231,079	2,192,827	413,989	(607,823)	166,400
Funds flow from (used in) operations(10)	**3,558,673**	2,559,898	2,634,985	(725,431)	1,387,470	1,251,089	99,720	714,801
Per share, basic and diluted	**0.04**	0.03	0.03	(0.01)	0.02	0.01	0.00	0.01
Net income (loss)	**2,854,615**	2,812,582	(889,224)	25,334	(236,344)	(2,253,163)	(2,389,393)	(3,308,520)
Per share, basic and diluted	**0.03**	0.03	(0.01)	0.00	(0.00)	(0.03)	(0.03)	(0.04)
Combined average realized price ($/boe)	**51.34**	59.44	51.85	22.78	55.36	58.64	43.96	49.80
Operating netback ($/boe)(11)	**30.64**	31.10	30.89	5.14	23.43	24.27	12.42	23.29

Notes:

(1) The increases in revenue, netbacks and funds flow from operations are due to increases in production rates.
(2) The increases in revenue and netbacks are due to increases in realized commodity prices.
(3) The increases in revenue, netbacks and funds flow from operations are due to increases in realized commodity prices.
(4) The decreases in revenue, netbacks and funds flow from (used in) operations are due to a sharp decrease in realized commodity prices.
(5) The increases in revenue and funds flow from operations are due to increases in production rates, while netbacks remained relatively the same due to the decrease in commodity prices.
(6) The increases in revenue, netbacks and funds flow from operations are due to increases in production rates and commodity prices.
(7) The decreases in netbacks and funds flow from operations are primarily due to the wider WCS/WTI differential and losses incurred from hedging contracts.
(8) The increases in revenue, netbacks and funds flow from operations are due to increases in production rates and commodity prices.
(9) The increases in revenue, netbacks and funds flow from operations are due to increases in production rates and commodity prices, as well as the realized commodity hedging gains.
(10) 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.
(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.

Outstanding Share Capital

	November 13, 2019	**September 30, 2019**	December 31, 2018
Fully diluted share capital			
Common shares issued and outstanding	89,153,802	**89,408,302**	89,793,302
Stock options	8,184,000	**8,184,000**	8,419,000
Warrants	13,750,000	**13,750,000**	13,750,000
Total fully diluted shares outstanding	111,087,802	**111,342,302**	111,962,302

On June 27, 2019 the Company announced notice of a normal course issuer bid (NCIB) to purchase and cancel, from time to time, up to 8,016,731 common shares of the Company. The Company has since purchased and canceled 475,000 shares as at September 30, 2019, and an additional 254,500 shares as of the date of this report.

The Company has the following stock options that are outstanding and exercisable as at November 13, 2019:

Exercise Price	Grant Date	Expiry Date	Balance Outstanding November 13, 2019	Balance Exercisable November 13, 2019
$0.24	January 29, 2015	January 29, 2020	1,000,000	1,000,000
$0.39	March 1, 2015	March 1, 2020	100,000	100,000
$0.08	February 11, 2016	February 11, 2021	1,595,000	1,595,000
$0.08	February 12, 2016	February 12, 2021	125,000	125,000
$0.25	September 21, 2017	September 21, 2022	4,914,000	4,914,000
$0.28	October 2, 2017	October 2, 2022	150,000	100,000
$0.25	January 1, 2018	January 1, 2023	250,000	166,667
$0.12	March 1, 2019	March 1, 2024	50,000	50,000
			8,184,000	8,050,667
Weighted-average exercise price			$0.21	$0.21

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.

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.

Hemisphere's corporate strategy through the remainder of 2019 is to focus on strengthening its balance sheet while optimizing new production and reducing per barrel operating and corporate costs. The Company plans to keep its 2019 capital expenditures within corporate cash flow, and any additional funds will be used to purchase shares as per Hemisphere's previously announced NCIB, fund the next phase of development drilling, or pay down debt.

a) Financing

The Company's net cash used in financing activities during the three and nine months ended September 30, 2019 were $143,984 and $196,902 respectively. These funds used are from the shares purchased under the NCIB, payment of term loan fees and lease liabilities in the periods.

b) 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.

An initial commitment amount of US$15.0 million (the "Term Loan") was granted at inception and on January 23, 2018 and June 1, 2018 the Company amended its credit agreement with its Lender to increase the commitment amount by US$5.0 million and US$10.0 million respectively. This brings the Company's aggregate amount committed by the Lender under the Term Loan to US$30.0 million.

As at September 30, 2019 the Company has drawn US$26.0 million (CAD$34,426,600), and as of the date of this report, has drawn an additional US$500,000 (CAD$661,000). The Company's ability to access additional commitments in excess of US$30.0 million is subject to approval of the Lender based on review and approval of the Company's future development plans.

The interest rate for the Term Loan is the three-month United States dollar London Interbank Offered Rate ("LIBOR") with a LIBOR floor of 1%, plus 7.50% payable quarterly, for a five-year term with a maturity date of September 15, 2022. In conjunction, the Company issued 13,750,000 warrants entitling the Lender to purchase one common share of Hemisphere at an exercise price of $0.28/share prior to September 15, 2022.

The Term Loan is subject to certain financial and performance covenants, which are listed below from the quarter ended September 30, 2019 and onward:

1. Interest coverage ratio shall not be less than 3.00 to 1.00.

2. Total leverage ratio shall not be more than 3.25 to 1.00.

3. Minimum average production shall not be less than 1,500 boe/d.

4. Proved developed producing coverage ratio, based on reserve reports internally prepared by Hemisphere, shall not be less than 1.00 to 1.00.

5. Total proved reserves coverage, based on reserve reports internally prepared by Hemisphere, shall not be less than 1.50 to 1.00.

6. The Company also has an annual financial covenant for its cash general and administrative costs for a base sum of $2.725 million per annum for the year ending December 31, 2019.

For the quarter ended September 30, 2019 the Company has met all of its financial and performance covenants in effect, as follows:

Ratio			Required	Actual September 30, 2019	
1.	Interest Coverage Ratio	Greater than	3.00	5.08	
2.	Total Leverage Ratio	Less than	3.25	1.99	
3.	Minimum Average Production	Greater than	1,500	1,738	Boe/d
4.	Proved Developed Producing Coverage Ratio	Greater than	1.00	1.54	
5.	Total Proved Reserves Coverage Ratio	Greater than	1.50	2.02	

Further details on the calculations of the covenants can be found in the Credit Agreement and the amendment thereto filed on SEDAR at www.sedar.com on September 22, 2017 and February 1, 2018 respectively, under the Company's profile.

c) 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, incurring additional indebtedness under the Term Loan, issuing new debt instruments, other financial or equity-based instruments, adjusting capital spending, or disposing of assets. The capital structure is reviewed on an ongoing basis.

Commitment

The Company has a commitment to make monthly rental payments pursuant to the office rental agreement at its current location until May 31, 2023.

As at September 30, 2019, the gross balance of the Term Loan was $34,426,600 (US$26,000,000), exclusive of the debt issuance costs. The Term Loan matures on September 15, 2022.

		2019	2020	2021	2022	2023	Total
Lease operating costs	$	19,107	76,428	76,428	76,428	31,845	280,236
Term loan		-	-	-	34,426,600	-	34,426,600
Term loan interest		845,077	3,380,307	3,380,307	2,535,230	-	10,140,921
	$	864,184	3,456,735	3,456,735	37,038,258	31,845	44,847,757

Off-Balance Sheet Arrangements

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

Proposed Transactions

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

Changes in Accounting Policies

Effective January 1, 2019, the Company adopted IFRS 16. The Company has applied the new standard using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening deficit and applies the standard prospectively. Therefore, the comparative information in the interim financial statements has not been restated.

On adoption, management elected to use the following practical expedients permitted under the new standard:

- account for leases with a remaining term of less than twelve months as at January 1, 2019 as short-term leases;
- account for lease payments as an expense and not recognize a right-of-use asset (ROU asset) if the underlying asset is of a low dollar value; and
- the use of hindsight in determining the lease term where the contract contains terms to extend or terminate the lease.

IFRS 16 requires entities to recognize lease liabilities in relation to leases which had previously been classified as operating leases under the principles of IAS 17, "Leases". Under the principles of IFRS 16 these leases have been measured at the present value of the remaining lease payments, discounted using the Company's incremental borrowing rates at January 1, 2019. Incremental borrowing rates as at January 1, 2019 is estimated at an average of 10.92%. The associated ROU assets were measured at the amount equal to the lease liability on January 1, 2019.

Adopting IFRS 16 impacted the Company's lease liabilities and ROU assets as follows, as at January 1, 2019:

- recorded lease liabilities of $452,152; and
- recorded ROU assets of $452,152

Adopting IFRS 16 impacted the Company's Q3 2019 financial results compared with what would have occurred had we not adopted the new accounting policy as follows:

	Three Months	Nine Months
• decreased gross general and administrative costs by	$17,721	$53,163
• decreased production costs in the amount of	$12,338	$37,014
• increased DD&A expenses in the amount of	$25,533	$76,599
• increased finance expenses in the amount of	$11,039	$34,518

Financial Instruments

Fair value estimates of financial instruments are made at a specific point in time, based on relevant information about financial markets and specific financial instruments. As these estimates are subjective in nature, involving uncertainties and matters of significant judgment, changes in assumptions can significantly affect estimated fair values. At September 30, 2019, the Company's financial instruments include cash and cash equivalents, accounts receivable, reclamation deposits, term loan, and accounts payable and accrued liabilities.

The fair values of cash and cash equivalents, accounts receivable, reclamation deposits and accounts payable and accrued liabilities approximate their carrying values due to the short-term maturity of these financial instruments. The fair value of the term loan is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date.

a) Fair value hierarchy

Fair value measurements of financial instruments are required to be classified using a fair value hierarchy that reflects the significance of inputs in making the measurements. The levels of the fair value hierarchy are defined as follows:

Level 1 - Quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2 - Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly.

Level 3 - Inputs for the asset or liability that are not based on observable market data.

b) Non-derivative financial instruments

Financial assets

At initial recognition, financial assets are classified into four main categories: loans and receivables; held-to-maturity investments; available for sale financial assets; or financial assets at fair value through profit or loss. All financial assets are recognized initially at fair value, normally being the transaction price, plus any directly attributable transaction costs. Transaction costs for instruments at fair value through profit or loss are recognized immediately in earnings.

The subsequent measurement of financial assets depends on their classification.

Loans, receivables and held-to-maturity investments are subsequently measured at amortized cost using the effective interest method, less any impairment losses. Gains and losses are recognized in earnings when the asset is derecognized or impaired, as well as through the amortization process.

Available-for-sale financial assets are subsequently measured at fair value, with changes in fair value recognized directly in other comprehensive income until the asset is derecognized or determined to be impaired, at which time the cumulative change in fair value previously reported in other comprehensive income is recognized in earnings.

Financial assets at fair value through profit or loss are subsequently measured at fair value, with changes in those fair values recognized in earnings.
Financial assets are derecognized when the contractual rights to the cash flows expire, or when substantially all the risks and rewards of ownership of the financial asset are transferred to a third party.

Financial assets and liabilities are shown separately in the statement of financial position unless the Company has a legal right to offset the amounts and intends to either settle on a net basis or to realize the asset and settle the liability simultaneously, in which case they are presented on a net basis.

Impairment of financial assets

A financial asset that is not carried at fair value through profit or loss is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that a loss event has occurred after initial recognition and has had a negative effect on the estimated future cash flows of that asset that can be estimated reliably.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the asset's original effective interest rate.

The Company considers evidence of impairment for receivables at both a specific asset and collective level. All individually significant financial assets are tested for impairment on an individual basis. All individually significant receivables found not to be specifically impaired are then collectively assessed for any impairment that has been incurred but not yet identified. The remaining financial assets are assessed collectively for impairment in groups that share similar credit risk characteristics.

In assessing collective impairment the Company uses historical trends of the probability of default, timing of recoveries and the amount of loss incurred, adjusted for management's judgment as to whether current economic and credit conditions are such that the actual losses are likely to be greater or less than suggested by historical trends.

All impairment losses are recognized in earnings.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in earnings.

Financial liabilities

At initial recognition, financial liabilities are classified as either financial liabilities at fair value through profit or loss, or other financial liabilities. All financial liabilities are recognized initially at fair value, normally being the transaction price less any directly attributable transaction costs. Transaction costs for instruments at fair value through profit or loss are recognized immediately in earnings.

The subsequent measurement of financial liabilities depends on their classification.
Financial liabilities at fair value through profit or loss are subsequently measured at fair value, with changes in those fair values recognized in earnings.

Other financial liabilities are subsequently measured at amortized cost using the effective interest method.

Financial liabilities are derecognized when the contractual obligation expires, is discharged, or cancelled. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognized in earnings.

c) Financial derivative instruments

The Company may use financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices and foreign exchange. These instruments are not used for trading or speculative purposes.

The Company has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though the Company considers all derivative contracts to be economic hedges. As a result, all financial derivative contracts are classified as fair value through profit or loss and are recognized at fair value. Transaction costs are recognized in earnings when incurred.

Physical delivery contracts are entered into for the purpose of delivery of oil in accordance with the Company's expected sale requirements, and therefore are not recorded in the statement of financial position. These contracts are recorded in revenue on their settlement dates.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative, and the combined instrument is not measured at fair value through profit or loss. Changes in the fair value of separable embedded derivatives are recognized in earnings.

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, 2019	December 31, 2018
Accounts receivable		
Marketing receivables	**$ 3,278,864**	$ 168,284
Trade receivables	**83,240**	104,454
Receivables from joint ventures	**7,102**	14,431
Reclamation deposits	**115,535**	115,535
	$ 3,484,741	$ 402,704

The Company sells the majority of its oil production to a single oil marketer 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, 2019, the Company had net debt (current assets less current liabilities excluding fair value of financial instruments) of $35,934,983 (December 31, 2018 - $35,446,384), which includes the gross term loan of $34,426,600 (December 31, 2018 - $35,458,800). The Company funds its operations through operating cash flows and the term loan, which has an additional US$4 million of borrowing base committed by its lender at September 30, 2019 plus an additional US$5 million of principle loan capacity.

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 $344,000 annual effect on net income.

Foreign currency risk

The Company's functional and reporting currency is Canadian dollars. The Company does not sell or transact in any foreign currency; except i) the Company's commodity prices are largely denominated in 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, and ii) the Company's Term Loan is denominated in USD and, as a result, the amount that the Company will be obligated to repay at the term of the loan will be affected by fluctuations in the exchange rate between the USD and the

Canadian dollar at that time. A one percent change in the foreign exchange rate would have a $286,000 effect on the annual net income.

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 funds flow from operations, and ability to raise capital. The Company has derivative commodity contracts in place as further disclosed within this MD&A and the interim financial statements for the nine months ended September 30, 2019.

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.

Non-IFRS Measures

This document contains the terms "funds flow from operations," "operating 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 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. Funds flow from operations is a measure that represents cash generated by operating activities, before changes in non-cash working capital and may not be comparable to measures used by other companies. 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 funds flow from operations to cash provided by operating activities is presented as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2019	2018	**2019**	2018
Cash provided by operating activities	**$ 3,803,909**	$ 2,192,827	**$ 6,966,814**	$ 1,998,995
Less: Change in non-cash working capital	**245,234**	805,358	**(1,786,742)**	(739,285)
Funds flow from operations	**$ 3,558,673**	$ 1,387,469	**$ 8,753,556**	$ 2,738,280
Per share, basic and diluted	**$ 0.04**	$ 0.02	**$ 0.10**	$ 0.03

a) 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.

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.

b) 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, and including the 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, 2019	December 31, 2018
Current assets(1)	**$ 4,636,141**	$ 2,258,590
Current liabilities(1)	**(6,144,524)**	(2,246,174)
Gross Term Loan(2)	**(34,426,600)**	(35,458,800)
Net debt	**$ (35,934,983)**	$ (35,446,384)

Note:
(1) Excluding fair value of financial instruments
(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: volumes and estimated net present value of the future net revenue of Hemisphere's oil and natural gas reserves; future oil and natural gas prices; future operational activities; and plans for continued growth in the Company's production, reserves and cash flow; and the expectation for the increasing of the Company's reserves 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; 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; 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.

Reserves Advisories

It should not be assumed that the net present value of the estimated net revenues of the reserve presented in herein represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions upon which such estimates are made will be attained and variances could be material. The reserve estimates of Hemisphere's crude oil, natural gas liquids and natural gas reserves and any estimated recovery factors provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.

Original Oil in Place

The reference to Original Oil-In-Place ("OOIP") in the Message to Shareholders is equivalent to Discovered Petroleum Initially-In-Place ("DPIIP"). DPIIP, as defined in the Canadian Oil and Gas Handbook, is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of DPIIP includes production, reserves and contingent resources; the remaining portion of DPIIP is unrecoverable. It should not be assumed that any portion of the OOIP/DPIIP set forth in the presentation is recoverable other than the portion which has been attributed reserves by McDaniel & Associates Consultants Ltd. There is uncertainty that it will be commercially viable to produce any portion of the OOIP/DPIIP other than the portion that is attributed reserves. The OOIP/DPIIP set forth in the Message to Shareholders has been provided for the sole purpose of highlighting the potential recovery factors for the reservoirs in which the Company holds an interest. The OOIP/DPIIP volumes set forth in the Message to Shareholders are from the mapping of the reservoirs by McDaniel & Associates Consultants Ltd. (who is independent of Hemisphere) in connection with preparing the Company's reserve report effective as of December 31, 2018.