www.hemisphereenergy.ca

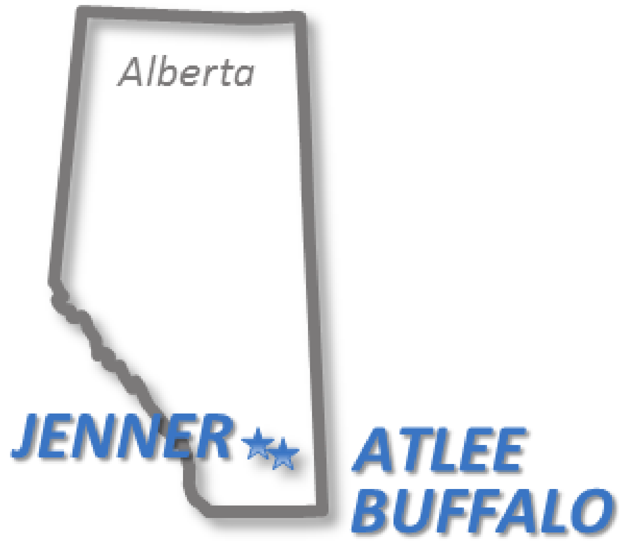
TSX-V: HME

Hemisphere energy corporation

2018
ANNUAL REPORT

Corporate Summary

Hemisphere Energy Corporation is a producing oil and gas company focused on developing conventional oil assets with low risk drilling opportunities. Hemisphere plans continual growth in production, reserves, and cash flow by focusing on existing assets with significant growth potential and executing strategic acquisitions. Hemisphere trades on the TSX Venture Exchange as a Tier 1 issuer under the symbol "HME".



2019 Annual General and Special Meeting of Shareholders

June 14, 2019 at 9:30 am Pacific Daylight Time
Oceanic Plaza, Pender Room
1035 West Pender Street, Vancouver, British Columbia

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2018 FINANCIAL AND OPERATING HIGHLIGHTS

	Year Ended December 31	
	2018	2017
OPERATING		
Average daily production		
Oil (bbl/d)	**1,062**	612
Natural gas (Mcf/d)	**287**	270
NGL (bbl/d)	**2**	2
Combined (boe/d)	**1,111**	659
Oil and NGL weighting	**96%**	93%
Average sales prices		
Oil ($/bbl)	**$ 45.26**	$ 47.94
Natural gas ($/Mcf)	**1.76**	2.33
NGL ($/bbl)	**54.75**	47.69
Combined ($/boe)	**$ 43.78**	$ 45.62
Operating netback ($/boe)		
Petroleum and natural gas revenue	**$ 43.78**	$ 45.62
Royalties	**7.60**	7.56
Operating costs	**11.15**	14.66
Transportation costs	**2.70**	2.90
Operating field netback(1)	**22.34**	20.50
Realized commodity hedging (gain) loss	**6.52**	0.08
Operating netback(2)	**$ 15.82**	$ 20.42
FINANCIAL		
Petroleum and natural gas revenue	**$ 17,756,439**	$ 10,974,634
Operating field netback(1)	**9,060,315**	4,391,894
Operating netback(2)	**6,415,532**	4,913,240
Cash flow provided by operating activities	**2,230,071**	1,915,248
Funds flow from operations(3)	**2,012,847**	2,476,049
Per share, basic and diluted	**0.02**	0.03
Net loss	**(4,853,569)**	(3,796,175)
Per share, basic and diluted	**(0.05)**	(0.04)
Capital expenditures	**16,057,316**	8,689,240
Net debt(4)	**35,446,384**	18,558,361
Gross term loan(5)	**$ 35,458,800**	$ 18,868,500

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) 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 gross term loan and excluding fair value of financial instruments and any flow-through share premium.

(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.

	As at December 31	
	2018	2017
RESERVES		
Proved (Mboe)(1)	**7,612.1**	4,922.7
Proved plus Probable (Mboe)(1)	**10,616.6**	7,174.8
COMMON SHARES		
Common shares outstanding	**89,793,302**	89,793,302
Stock options outstanding	**8,419,000**	8,169,000
Warrants outstanding	**13,750,000**	13,750,000
Fully diluted shares outstanding	**111,962,302**	111,712,302
Weighted-average shares outstanding – basic and diluted	**89,793,302**	88,495,660

Note:

(1) Reserves as attributed by the Company's independent reserves evaluator, McDaniel & Associates Consultants Ltd., in its report dated March 9, 2018 and effective as of December 31, 2018, prepared in accordance with the COGE Handbook and National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities.

MESSAGE TO SHAREHOLDERS

Dear Fellow Hemisphere Shareholders,

I would like to start by thanking you for your continued support through the volatility and trials that the Canadian energy sector endured in 2018. From world oil price fluctuations and Canadian oil price differential blowouts, to pipeline delays and restricted access to capital, 2018 brought many struggles. Nevertheless, through it all I am pleased to say that Hemisphere rose to the challenge and made record corporate progress.

Hemisphere achieved tremendous operational performance in 2018, executing a $16.1 million capital expenditure program which included 14 new horizontal wells and numerous facility upgrades. The successful drilling campaign resulted in a 69% increase in annual production rate to 1,111 boed (96% oil) and a fourth quarter average production rate of 1,378 boed (95% oil). Along with our increase in production Hemisphere realized a 21% reduction in its operating and transportation costs over the previous year to $13.85 per boe. These are significant accomplishments and have helped increase cash flow in a volatile price environment.

Hemisphere's drilling success has led to exciting reserve additions in all categories, with the highlight being a 71% increase in Proved plus Probable (2P) net present value of future net revenue (discounted at 10%, before tax) to $197.9 million, as well as a 2P reserve volume increase of 48% to 10.6 million barrels of oil equivalent (98% oil).

The achievements through 2018 are a direct result of the hard work and dedication of the Hemisphere team and associated field staff, consultants, contractors, and service companies engaged. I'd like to personally thank everyone for their commitment to Hemisphere and I look forward to working together through 2019 to build upon our 2018 accomplishments.

In looking ahead, Hemisphere has an exciting future with the continued development of our long life, shallow decline, oil-rich assets with low capital and operating costs and high rates of return. We are committed to matching our recent growth with strengthening our balance sheet and focusing on increased cash flow and shareholder value.

Thank you for your confidence and support.

Best regards,

(Signed) *"Don Simmons"*
Don Simmons, P.Geol.
President & Chief Executive Officer
April 24, 2019

Please refer to the attached Management's Discussion and Analysis for Reader Advisories regarding, among other matters, forward-looking information, non-IFRS measures, analogous information, reserves advisories and original oil in place. This Message to Shareholders should be read in conjunction with the audited annual financial statements of Hemisphere Energy Corporation together with Management's Discussion and Analysis for the year ended December 31, 2018, which can be found on SEDAR at www.sedar.com and is subject to the same cautionary statements as set out therein.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Dated as at April 24, 2019

The following Management's Discussion and Analysis ("MD&A") is a review of the operations and current financial position for the year ended December 31, 2018 for Hemisphere Energy Corporation ("Hemisphere" or the "Company") and should be read in conjunction with the audited Annual Financial Statements and related notes as at and for the years ended December 31, 2018 and 2017. 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 audited annual financial statements which were prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB").

This MD&A contains non-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 Jenner and Atlee Buffalo properties in southeast Alberta. The Company is headquartered in Vancouver, British Columbia and is traded on the TSX Venture Exchange under the symbol "HME".

Jenner, Alberta

Hemisphere has a 100% working interest in 13,411 net acres and has continued to build a land position in the Jenner area through Crown land sales and strategic acquisitions. The property is accessible year-round and is located east of Brooks in southeastern Alberta.

Atlee Buffalo, Alberta

The Company operates 100% of its wells in the Atlee Buffalo area. The property is accessible year-round and is located 30 kilometers east of the Company's Jenner property in southeastern Alberta. Hemisphere has a 100% working interest in 15,520 net acres and has been building a land position in Atlee Buffalo through Crown land sales and strategic acquisitions since 2013.

Operating Results

The Company generated funds flow from operations of $2,012,847 ($0.02/share) for the year ended December 31, 2018, as compared to $2,476,049 ($0.03/share) for the year ended December 31, 2017. For the fourth quarter of 2018, the Company generated negative funds flow from operations of $725,431 ($0.01/share) as compared to positive funds flow from operations of $714,801 ($0.01/share) for the fourth quarter of 2017.

The decreases in funds flow from operations for both the year ended and three months ended December 31, 2018 are the result of a sharp decrease in commodity prices in the fourth quarter of 2018.

The Company reported a net loss of $4,853,569 ($0.05/share) for the year ended December 31, 2018 as compared to a net loss of $3,796,175 ($0.04/share) for the year ended December 31, 2017. For the fourth quarter of 2018, the Company reported a net income of $25,334 ($0.00/share) compared to a net loss of $3,308,520 ($0.04/share) for the fourth quarter of 2017.

Production

	Three Months Ended December 31		Year Ended December 31	
By product	**2018**	2017	**2018**	2017
Oil (bbl/d)	**1,313**	725	**1,062**	612
Natural gas (Mcf/d)	**377**	259	**287**	270
NGL (bbl/d)	**2**	2	**2**	2
Total (boe/d)	**1,378**	770	**1,111**	659
Oil and NGL weighting	**95%**	94%	**96%**	93%

In the fourth quarter of 2018, the Company's average daily production was 1,378 boe/d (95% oil and NGL). This represents a 79% increase in production from the fourth quarter of 2017. The Company's average daily production for the year ended December 31, 2018 increased by 69% to 1,111 boe/d (96% oil and NGL) from the year ended December 31, 2017. This increase in production can be attributed to the 11 new producing wells drilled and placed on production during 2018, 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 December 31		Year Ended December 31	
	2018	2017	**2018**	2017
Benchmark Prices				
WTI (US$/bbl)[(1)]	**$ 58.81**	$ 55.40	**$ 64.76**	$ 50.94
Exchange rate (Cdn$/US$)	**1.3221**	1.2705	**1.2957**	1.2966
WTI (C$/bbl)	**77.76**	70.38	**83.91**	66.05
WCS (C$/bbl)[(2)]	**36.01**	48.44	**52.43**	48.93
AECO natural gas ($/Mcf)[(3)]	**1.62**	1.72	**1.54**	2.20
Average realized prices				
Crude oil ($/bbl)	**23.20**	52.02	**45.26**	47.94
Natural gas ($/Mcf)	**2.19**	2.05	**1.76**	2.33
NGL ($/bbl)	**47.65**	53.01	**54.75**	47.69
Combined ($/boe)	**$ 22.78**	$ 49.80	**$ 43.78**	$ 45.62

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 in the fourth quarter. 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 54% from $49.80/boe during the fourth quarter of 2017 to $22.78/boe for the fourth quarter of 2018. For the year ended December 31, 2018, the Company's combined average realized price decreased by 4% to $43.78/boe from $45.62 in 2017. These decreases are the result of lower oil prices during the three and twelve months ended December 31, 2018, which are reflected in the respective $28.82/bbl and $2.68/bbl decreases from the Company's average realized crude oil price during the same periods in 2017.

The Company's average realized natural gas price decreased for the year ended December 31, 2018 by $0.57/Mcf over the comparable period in 2017.

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

Product	Type	Volume	Price	Index	Term
Crude oil	Swaption	150 bbl/d	US$54.65	WTI-NYMEX	July 1, 2018 – February 28, 2019
Crude oil	Swap	250 bbl/d	US$19.20	WCS	January 1, 2019 – March 31, 2019
Crude oil	Swap	200 bbl/d	US$18.10	WCS	February 1, 2019 – March 31, 2019
Crude oil	Collar	200 bbl/d	US$56.00-US$59.00	WTI-NYMEX	March 1, 2019 – June 30, 2019
Crude oil	Swap	100 bbl/d	US$12.60	WCS	April 1, 2019 – June 30, 2019
Crude oil	Swap	350 bbl/d	US$10.50	WCS	May 1, 2019 – June 30, 2019
Crude oil	Swap	250 bbl/d	US$13.50	WCS	April 1, 2019 – September 30, 2019
Crude oil	Swap	200 bbl/d	US$13.65	WCS	April 1, 2019 – September 30, 2019
Crude oil	Swap	100 bbl/d	US$17.30	WCS	July 1, 2019 – September 30, 2019
Crude oil	Swap	100 bbl/d	US$15.45	WCS	July 1, 2019 – September 30, 2019
Crude oil	Collar	100 bbl/d	US$55.00-US$63.25	WTI-NYMEX	July 1, 2019 – September 30, 2019
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	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 December 31, 2018, the commodity contracts were fair valued as an asset value of $855,876 recorded on the balance sheet, and unrealized gains of $6,593,138 and $3,279,258 were recorded for the three months and year ended December 31, 2018, respectively (December 31, 2017 – loss of $2,644,411 and $2,423,282 respectively).

Revenue

	Three Months Ended December 31		Year Ended December 31	
	2018	2017	**2018**	2017
Oil	**$ 2,802,944**	$ 3,469,957	**$ 17,539,990**	$ 10,715,271
Natural gas	**76,040**	48,734	**184,511**	229,682
NGL	**7,856**	9,873	**31,938**	29,679
Total	**$ 2,886,840**	$ 3,528,565	**$ 17,756,439**	$ 10,974,634

Revenue decreased by 18% for the three months and increased by 62% for the year ended December 31, 2018 respectively, over the comparable periods in 2017. The annual increase in revenue is due to increased production volumes despite lower average realized prices in 2018 due to, a sharp decrease in realized prices in the fourth quarter due to widening price differentials between US benchmark WTI and discounted Canadian WCS.

Operating Netback

	Three Months Ended December 31		Year Ended December 31	
	2018	2017	**2018**	2017
Operating netback				
Revenue	**$ 2,886,840**	$ 3,528,565	**$ 17,756,439**	$ 10,974,634
Royalties	**384,485**	539,402	**3,081,225**	1,817,607
Operating costs	**1,129,698**	928,222	**4,521,940**	3,527,059
Transportation costs	**349,376**	213,756	**1,092,959**	698,074
Operating field netback(1)	**1,023,282**	1,847,185	**9,060,315**	4,931,894
Realized commodity hedging loss	**371,319**	196,739	**2,644,783**	18,654
Operating netback(2)	**$ 651,962**	$ 1,650,446	**$ 6,415,532**	$ 4,913,240
Operating netback ($/boe)				
Revenue	**$ 22.78**	$ 49.80	**$ 43.78**	$ 45.62
Royalties	**3.03**	7.61	**7.60**	7.56
Operating costs	**8.91**	13.10	**11.15**	14.66
Transportation costs	**2.76**	3.02	**2.70**	2.90
Operating field netback(1)	**8.07**	26.07	**22.34**	20.50
Realized commodity hedging loss	**2.93**	2.78	**6.52**	0.08
Operating netback(2)	**$ 5.14**	$ 23.29	**$ 15.82**	$ 20.42

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 fourth quarter of 2018 were $3.03/boe, representing a 60% decrease from the fourth quarter of 2017. This fourth quarter reduction was the result of a sharp decrease in oil prices during the fourth quarter of 2018, which directly impacts the Crown royalty par price. For the year ended December 31, 2018, royalties increased by 70% from the comparable period in 2017 commensurate with higher production. Overall, royalties year-over-year were similar on a per boe basis.

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 months and year ended December 31, 2018 increased on an absolute basis by 22% and 28%, respectively, but decreased on a per boe basis by $4.19 and $3.51, respectively, over the same periods in 2017. The increase to absolute operating costs is the result of more production and associated operating wellbores, while the decrease per boe is due to 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 $2.76/boe during the fourth quarter of 2018, which is a 9% decrease from the comparable quarter in 2017. Transportation costs were $2.70/boe for the year ended December 31, 2018, which represents a 7% decrease from the same period in 2017. The company's installation of handling facilities led to a reduction in trucked water, resulting in a decrease in trucking for the three months and year ended December 31, 2018 over the comparable periods in 2017.

Operating field netback of $8.07/boe for the three months ended December 31, 2018 was 69% lower than the comparable quarter in 2017, mainly due to the 54% decrease in the Company's combined average realized price, offset somewhat by higher production rates for the period, as discussed above. For the year ended December 31, 2018 operating netback was $15.82/boe, which is 23% lower than the same period in 2017. This decrease is primarily attributable to a net $6.44 increase in realized hedging losses for the year ended December 31, 2018, despite a higher operating field netback of $1.84 as compared to the previous year.

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 expense decreased for the three months and year ended December 31, 2018 by $353,299 and $355,788 respectively, from the comparable periods of 2017. Exploration and evaluation expense for the three months and year ended December 31, 2017 included undeveloped properties and land expiries occurring in 2018.

Depletion and Depreciation

	Three Months Ended December 31				Year Ended December 31			
		2018		2017		**2018**		2017
Depletion expense	**$**	**1,268,969**	$	842,602	**$**	**4,455,421**	$	3,090,462
Depreciation expense		**1,370**		1,845		**5,480**		7,377
Total	**$**	**1,270,338**	$	844,447	**$**	**4,460,900**	$	3,097,839
$ per boe	**$**	**10.02**	$	11.92	**$**	**11.00**	$	12.88

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 December 31, 2018 decreased to $10.02/boe from $11.92/boe for the same period in 2017. For the year ended December 31, 2018, depletion and depreciation expenses decreased to $11.00/boe from $12.88/boe for the same period in 2017. The decrease in depletion expense for the periods ended December 31, 2018 as compared to the same periods in 2017 is 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.

Impairment

At December 31, 2018, the Company performed an assessment of potential impairment indicators on each of its Cash Generating Units (CGUs), and management determined that an impairment test on its petroleum and natural gas assets was required due to volatile and low commodity prices. It was determined that the carrying amount of Jenner exceeded its recoverable amount of $11,682,760 for the year ended December 31, 2018 (year ended December 31, 2017 - $16,411,131). Accordingly, the Company recognized an impairment charge of $1,413,268 as at December 31, 2018 (December 31, 2017 - $nil). It was also determined that the Company would impair its three non-core natural gas properties which were not assigned economic reserves. Accordingly, the Company recognized an impairment charge in aggregate of $161,604 for the three natural gas properties for the year ended December 31, 2018 (year ended December 31, 2017 - $nil). No impairment was recognized for Atlee Buffalo as its recoverable value exceeded the carrying amount.

The recoverable amounts 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, loss factors and discount rates specific to the underlying composition of assets residing in each CGU.

Capital Expenditures

	Three Months Ended December 31		Year Ended December 31	
	2018	2017	**2018**	2017
Land and lease	**$ 22,846**	$ 49,849	**$ 46,061**	$ 74,649
Geological and geophysical	**100,703**	60,028	**373,058**	225,906
Drilling and completions	**612,320**	2,604,811	**11,489,920**	5,058,543
Investment in facilities	**733,415**	1,948,754	**4,148,277**	3,330,142
Total capital expenditures(1)	**$ 1,469,284**	$ 4,663,442	**$ 16,057,316**	$ 8,689,240

Note:

(1) Total capital expenditures exclude decommissioning costs and non-cash items.

The development capital spent during the year ended December 31, 2018 included capital associated with drilling and completing three new wells in the spring and eleven new wells in the summer of 2018, as well as upgrading both of the Atlee Buffalo batteries.

General and Administrative Expense ("G&A")

	Three Months Ended December 31		Year Ended December 31	
	2018	2017	**2018**	2017
Gross G&A	**$ 696,885**	$ 690,019	**$ 2,385,043**	$ 1,971,364
Capitalized G&A	**(95,242)**	(137,476)	**(509,788)**	(386,528)
Total	**$ 601,644**	$ 552,543	**$ 1,875,256**	$ 1,584,837
$ per boe	**$ 4.75**	$ 7.80	**$ 4.62**	$ 6.59

Gross G&A costs for the three and twelve months ended December 31, 2018 increased slightly by 1% and 21% respectively over the comparable periods of 2017 due to increased activity resulting in higher consulting fees and salaries.

The Company capitalizes the portion of general and administrative expenses which can be attributed to costs incurred during the period relating to its development and exploration activities. For the year ended December 31, 2018, capitalized G&A increased by 32% from the comparable period in 2017 and is due to the Company completing spring and summer drilling programs in 2018.

For the three and twelve months ended December 31, 2018, the Company realized a decrease of $3.05/boe and $1.97/boe respectively in general and administrative costs compared to the same periods in 2017. This is a result of increased production which offset the increased gross general and administrative expenses over the same periods in 2017.

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. For the years ended December 31, 2018 and 2017, the Company recorded share-based payments of $263,235 and $233,508, respectively.

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. While no stock options were granted in the fourth quarter of 2018, $88,283 of options vested regarding grants issued in prior fiscal periods.

	Three Months Ended December 31		Year Ended December 31	
	2018	2017	**2018**	2017
Share-based payments	**$ 88,283**	$ 18,028	**$ 263,235**	$ 233,508
Capitalized costs	**-**	4,491	**101,613**	99,161
Total share-based payments	**$ 88,283**	$ 22,519	**$ 364,848**	$ 332,669

Finance Expense

	Three Months Ended December 30		Year Ended December 30	
	2018	2017	**2018**	2017
Interest expense	**$ 874,503**	$ 382,649	**$ 2,664,211**	$ 834,078
Accretion of debt issuance costs	**144,866**	74,037	**293,681**	87,837
Amortization of deferred charges	**(22,762)**	46,453	**202,332**	48,738
Accretion of decommissioning liabilities	**34,586**	26,932	**138,345**	107,727
Total	**$ 1,031,194**	$ 530,070	**$ 3,298,569**	$ 1,078,380
$ per boe	**$ 8.14**	$ 8.46	**$ 8.13**	$ 4.48

Interest expense for the three and twelve months ended December 31, 2018 increased by $491,854 and $1,830,133 over the respective periods in 2017. This increase is a result of higher interest incurred on the new term loan secured in September 2017, which carries a higher interest rate and balance over the retired bank credit facility from the comparable periods in 2017.

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 twelve months ended December 31, 2018 accretion expense increased by 28% over the comparable periods in 2017 due to the additional abandonment and reclamation costs associated with the new wells drilled.

Tax Pools

The Company has approximately $69.5 million (2017 - $56.3 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 2018 and any taxes payable beyond 2018 will primarily be a function of commodity prices, capital expenditures and production volumes.

	Deduction Rate	**December 31, 2018**	December 31, 2017
Canadian exploration expense (CEE)	100%	**$ 3,336,823**	$ 3,336,823
Canadian development expense (CDE)	30%	**21,995,676**	15,671,786
Canadian oil and gas property expense (COGPE)	10%	**5,480,200**	6,089,111
Non-capital losses carry forwards (NCL)	100%	**36,314,261**	29,648,931
Undepreciated capital cost (UCC)	20-55%	**896,082**	1,182,138
Share issuance costs and other	Various	**1,465,252**	340,199
Total		**$ 69,488,294**	$ 56,268,988

Selected Annual Information

The following are highlights of the Company's financial data for the three most recently completed fiscal years:

	Year Ended December 31		
	2018	2017	2016
Average daily production (boe/d)	**1,111**	659	527
Petroleum and natural gas revenue	**$ 17,756,439**	$ 10,974,634	$ 6,221,497
Operating netback[(1)]	**6,415,532**	4,913,240	2,347,747
Cash provided by operating activities	**2,230,071**	1,915,248	432,604
Funds flow from operations[(2)]	**2,012,847**	2,476,049	530,567
Per share, basic and diluted	**0.02**	0.03	0.01
Net loss	**(4,853,569)**	(3,796,175)	(2,680,648)
Per share, basic and diluted	**(0.05)**	(0.04)	(0.03)
Average realized price ($/boe)	**43.78**	45.62	32.23
Operating netback ($/boe)[(1)]	**15.82**	20.42	12.16
Capital expenditures, including property acquisitions	**16,057,316**	8,689,241	2,722,375
Net debt[(3)]	**35,446,384**	18,558,361	11,827,170
Bank indebtedness	**-**	-	11,247,537
Gross term loan[(4)]	**35,458,800**	18,868,500	-
Total assets	**$ 59,197,488**	$ 49,069,803	$ 39,696,007

Notes:

(1) *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.*

(2) *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.*

(3) *Net debt is a non-IFRS measure calculated as current assets minus current liabilities including gross term loan or bank indebtedness and excluding fair value of financial instruments and any flow-through share premium.*

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

Summary of Quarterly Results

	2018				2017			
	Dec. 31 Q4[(1)]	Sep. 30 Q3[(2)]	Jun. 30 Q2[(3)]	Mar. 31 Q1[(4)]	Dec. 31 Q4[(5)]	Sep. 30 Q3[(6)]	Jun. 30 Q2[(7)]	Mar. 31 Q1[(8)]
Average daily production (boe/d)	1,378	1,150	1,053	858	770	681	600	583
Petroleum and natural gas revenue	2,886,840	5,856,762	5,618,915	3,393,921	3,528,565	2,733,656	2,419,666	2,292,746
Operating field netback[(9)]	1,023,282	3,239,217	3,279,840	1,517,979	1,650,446	1,208,106	1,096,412	958,276
Cash provided by operating activities	231,079	2,192,827	413,989	(604,823)	166,400	955,787	612,221	180,842
Funds flow from (used in) operations[(10)]	(725,431)	1,387,470	1,251,089	99,720	714,801	657,840	598,078	505,331
Per share, basic and diluted	(0.01)	0.02	0.01	0.00	0.01	0.01	0.01	0.01
Net income (loss)	25,334	(236,344)	(2,253,163)	(2,389,393)	(3,308,520)	(142,254)	(206,724)	(138,678)
Per share, basic and diluted	0.00	(0.00)	(0.03)	(0.03)	(0.04)	(0.00)	(0.00)	(0.00)
Combined average realized price ($/boe)	22.78	55.36	58.64	43.96	49.80	43.62	44.34	43.68
Operating netback ($/boe)[(11)]	5.14	23.43	24.27	12.42	23.29	19.28	20.09	18.26

Notes:

(1) *The decreases in revenue, netbacks and funds flow from operations are due to a sharp decrease in commodity prices.*

(2) *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.*

(3) *The increases in revenue, netbacks and funds flow from operations are due to increases in production rates and commodity prices.*

(4) *The decreases in netbacks and funds flow from operations are primarily due to the wider WCS/WTI differential and losses incurred from hedging contracts.*

(5) *The increases in revenue, netbacks and funds flow from operations are due to increases in production rates and commodity prices.*

(6) *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.*

(7) *The increases in revenue and netbacks are due to an 8% increase in the Company's combined average realized price and 31% lower general and administrative costs from the previous quarter.*

(8) *Revenues in this quarter increased as a result of higher production and an increase in the combined average realized price.*

(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) *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.*

(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 Data

	April 24, 2018	**December 31, 2018**	December 31, 2017
Fully diluted share capital			
Common shares issued and outstanding	89,883,302	**89,793,302**	89,793,302
Stock options	8,184,000	**8,419,000**	8,169,000
Warrants	13,750,000	**13,750,000**	13,750,000
Total fully diluted shares outstanding	111,817,302	**111,962,302**	111,712,302

The Company has the following stock options that are outstanding and exercisable as at December 31, 2018:

Exercise Price	Grant Date	Expiry Date	Balance Outstanding Dec. 31, 2017	Changes in the Year Granted	Exercised	Expired	Balance Outstanding Dec. 31, 2018	Balance Exercisable Dec. 31, 2018
$0.24	29-Jan-15	29-Jan-20	1,075,000	-	-	-	1,075,000	1,075,000
$0.39	1-Mar-15	1-Mar-20	100,000	-	-	-	100,000	100,000
$0.08	11-Feb-16	11-Feb-21	1,685,000	-	-	-	1,685,000	1,685,000
$0.08	12-Feb-16	12-Feb-21	125,000	-	-	-	125,000	125,000
$0.25	21-Sep-17	21-Sep-22	5,034,000	-	-	-	5,034,000	3,356,000
$0.28	2-Oct-17	2-Oct-22	150,000	-	-	-	150,000	100,000
$0.25	01-Jan-18	01-Jan-23	-	250,000	-	-	250,000	83,333
			8,169,000	250,000	-	-	8,419,000	6,524,333
Weighted-average exercise price			$0.21	$0.25	-	-	$0.21	$0.20

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.

a) Financing

The Company's net cash provided by financing activities during the three and twelve months ended December 31, 2018 were $5,173,100 and $13,746,745 respectively. These funds are from the proceeds, net of debt issuance costs, which the Company received from the additional draws on the term loan in 2018 of US$11 million. These funds were used for expenditures in the Company's spring and summer drilling programs.

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 December 31, 2018 the Company has drawn US$26.0 million (CAD$35,458,800). 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 fourth quarter ended December 31, 2018 and onward:

1. Interest coverage ratio for the quarter ended December 31, 2018 shall not be less than 2.50 to 1.00; quarter ended March 31, 2019 and each quarter thereafter shall not be less than 3.00 to 1.00.

   Interest coverage ratio, as defined in the Credit Agreement, means the ratio as of the last day of any fiscal quarter of (a) Adjusted EBITDAX as defined below for the applicable fiscal quarter to (b) Interest Expense for such fiscal quarter.

2. Total leverage ratio for the quarter ended December 31, 2018 shall not be more than 4.25 to 1.00; quarters ended March 31, 2019 and June 30, 2019 shall not be more than 3.50 to 1.00; quarter ended September 30, 2019 and each quarter thereafter shall not be more than 3.25 to 1.00.

   Total leverage ratio, as defined in the Credit Agreement, means the ratio as of the last day of any fiscal quarter of (a) Total Debt as of such date to (b) Adjusted EBITDAX for the fiscal quarter ending on such date calculated on an annualized basis.

3. Minimum average production for the quarter ended December 31, 2018 will not be less than 1,100 boe/d; quarters ended March 31, 2019 and June 30, 2019 will not be less than 1,300

boe/d; quarter ended September 30, 2019 and each quarter thereafter will not be less than 1,500 boe/d.

4. Proved developed producing coverage ratio for the quarter ended December 31, 2018, based on reserve reports internally prepared by Hemisphere, and each quarter thereafter shall not be less than 1.00 to 1.00.

   Proved developed producing coverage ratio, as defined in the Credit Agreement, means as of any date of determination, the ratio of (a) proved developed producing reserves on a pre-tax basis at 10% to (b) the sum of (i) Total Debt and (ii) without duplication of clause (a) above, all obligations (after giving effect to any netting requirements) under any swap agreement that such person would be required to pay if the swap agreement was terminated at such time, in each case, as of such date. Notwithstanding anything to the contrary contained herein, after giving effect to the netting contemplated by clause (ii) above, in no event shall amounts owing to any credit party under any swap agreement result in a reduction of the obligations referred to in clause (b).

5. Total proved reserves coverage ratio for the quarter ended December 31, 2018, based on reserve reports internally prepared by Hemisphere, and each quarter thereafter shall not be less than 1.50 to 1.00.

   Total proved reserves coverage ratio, as defined in the Credit Agreement, means as of any date of determination, the ratio of (a) the Total Proved reserves on a pre-tax basis discounted at 10% to (b) the sum of (i) Total Debt and (ii) without duplication of clause (a) above, all obligations (after giving effect to any netting requirements) under any swap agreement that such person would be required to pay if the swap agreement were terminated at such time, in each case, as of such date. Notwithstanding anything to the contrary contained herein, after giving effect to the netting contemplated by clause (ii) above, in no event shall amounts owing to any credit party under any swap agreement result in a reduction of the obligations referred to in clause (b).

   Definition of certain terms as defined in the Credit Agreement:

   Interest Expense means, for any period, total cash interest expense (excluding accretion of asset retirement obligation and debt issuance costs and including that portion attributable to capital leases in accordance with GAAP and capitalized interest) of the credit parties and their subsidiaries on a basis with respect to all outstanding Total Debt.

   Total Debt means, as at any date of determination: (a) the aggregate amount of all Indebtedness of the credit parties and their Subsidiaries determined on a basis in accordance with GAAP plus (b) the aggregate outstanding amount, without duplication, of attributable debt of the credit parties and their subsidiaries determined on a basis.

   Adjusted EBITDAX means, for any period, an amount determined for the Company on a basis equal to:

the amounts for such period of net income,

plus
the sum, without duplication, of the amounts for such period of the following expenses (or charges) to the extent deducted from net income during such period:

(i) Interest Expense, plus
(ii) Provisions for taxes based on income (including margin or gross receipts taxes), plus
(iii) Total depreciation and amortization expense, plus
(iv) Impairment or asset write-down expense, plus
(v) Accretion of asset retirement obligation and debt issuance costs, plus
(vi) Share-based compensation expense, plus
(vii) Non-cash losses resulting from the mark-to-market exposure of outstanding swaps and unrealized foreign exchange exposure, plus
(viii) Other non-Cash items reducing net income (excluding any such non-cash item to the extent that it represents an accrual or reserve for potential Cash items in any future period or amortization of a prepaid Cash item that was paid in a prior period),

minus
the sum, without duplication of the amounts for such period of the following items to the extent increasing net income during such period:

i) Other non-Cash items increasing net income for such period (excluding any such non-Cash item to the extent it represents the reversal of an accrual or reserve for potential Cash item in any prior period), plus
ii) Interest income, plus
iii) Non-cash gains resulting from the mark-to-market exposure of outstanding swaps and unrealized foreign exchange exposure.

The Company also has a financial covenant for its cash General and Administrative costs ("G&A costs") that it shall not exceed 105% of the cash G&A costs cap of $2.5 million per annum as at December 31, 2018.

For the quarter ending December 31, 2018 the Company has met its required Minimum Average Production and its G&A costs covenants as required. The two financial covenants (being the interest coverage ratio and total leverage ratio covenants) and two reserve-based covenants (being the PDP coverage ratio and total proved reserve coverage ratio covenants) were waived for the quarter ended December 31, 2018.

Ratio			Required	Actual Dec. 31, 2018	
1.	Interest Coverage Ratio	Greater than	2.50	Waived	
2.	Total Leverage Ratio	Less than	4.25	Waived	
3.	Minimum Average Production	Greater than	1,100	1,378	Boe/d
4.	Proved Developed Producing Coverage Ratio	Greater than	1.00	Waived	
5.	Total Proved Reserves Coverage Ratio	Greater than	1.50	Waived	
6.	General and Administrative Costs	Less than	$2.65	$2.39	$MM

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.

Related Party Transactions

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

	Three Months Ended December 31		Years Ended December 31	
	2018	2017	**2018**	2017
Salaries and wages	**$ 265,000**	$ 205,000	**$ 940,000**	$ 768,333
Share-based payments	**-**	-	**137,499**	172,575

Commitments

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 December 31, 2018, the gross balance of the Term Loan was $35,458,800 (US$26,000,000), exclusive of the debt issuance costs. The Term Loan matures on September 15, 2022.

	2019	2020	2021	2022	2023	Total
Office Rental	$ 142,864	142,864	142,864	142,864	59,527	630,982
Term Loan	-	-	-	35,458,800	-	35,458,800
Term Loan Interest	3,127,466	3,127,466	3,127,466	2,345,600	-	11,727,998
	$ 3,270,330	3,270,330	3,270,330	37,947,264	59,527	47,817,781

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.

Critical Accounting Estimates

The Company's significant accounting estimates, judgments and policies are set out in Notes 2 and 3 of the audited annual financial statements for the year ended December 31, 2018 and have been consistently followed in the preparation of the audited annual financial statements.

The preparation of these audited annual financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that may affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. A discussion of specific estimates and judgments employed in the preparation of the Company's unaudited interim condensed financial statements is included in the Company's audited annual financial statements for the year ended December 31, 2018.

An additional significant area of estimation, uncertainty and critical judgment in applying accounting policies that has a significant effect on the amount recognized in the financial statements is foreign exchange. Estimates of foreign exchange conversion to value US dollar dominated amounts into Canadian currency include the Term Loan, cash balances and hedging contracts.

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

Newly Adopted Accounting Standards

Adoption of IFRS 15 "Revenue from Contracts with Customers"

IFRS 15 "Revenue from Contracts with Customers" ("IFRS 15") was issued by the IASB in May of 2014 and replaces IAS 18 "Revenue", IAS 11 "Construction Contracts", and related interpretations effective for reporting periods beginning on or after January 1, 2018. The new standard provides a single, principles based five-step analysis of transactions to determine the nature of an entity's obligation to perform and whether, how much and when revenue is recognized.

The Company has adopted IFRS 15 effective January 1, 2018 and applied IFRS 15 to all of its contracts with customers using the modified respective method. Under this method, prior period financial statements have not been restated. Management reviewed the Company's revenue streams and major contracts with customers using the IFRS 15 principles-based five-step model and concluded there were no material changes to earnings or in the timing of when production revenue is recognized.

Adoption of IFRS 9 "Financial Instruments"

On January 1, 2018, the Company adopted all of the requirements of IFRS 9 "Financial Instruments" ("IFRS 9") which replaces IAS 39 "Financial Instruments: Recognition and Measurement" ("IAS 39"). The retrospective adoption of IFRS 9 had no material impact to the Company's financial statements.

IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost; fair value through other comprehensive income ("FVOCI"); or fair value through profit or loss ("FVTPL"). The classification of financial assets under IFRS 9 is generally based on the business model in which a financial asset is managed and its contractual cash flow characteristics. IFRS 9 eliminates the previous IAS 39 categories of held to maturity, loans and receivables and available for sale. IFRS 9 largely retains the existing requirements in IAS 39 for the classification of financial liabilities. IFRS 9 replaces the "incurred loss" model in IAS 39 with an "expected credit loss" model. The application of the new expected credit loss model did not have a significant impact on the Company's financial assets. Cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities and term loan continue to be measured at amortized cost and are now classified as "amortized cost".

There were no changes to the Company's classification of its financial instrument derivative assets and liabilities as FVTPL. The Company currently has no intentions of designating any of its financial instruments as hedges, nor does the Company currently apply hedge accounting.

Future Accounting Pronouncements

The Company has reviewed new and revised accounting pronouncements listed below that have been issued but are not yet effective. There are no other standards or interpretations issued, but not yet adopted, that are anticipated to have a material effect on the reported earnings or net assets of the Company.

Leases - In January 2016, the IASB issued IFRS 16 "Leases", which replaces the current IFRS guidance on leases. Under the current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the balance sheet, while operating leases are recognized in profit or loss when the expense is incurred.

Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. The recognition of the present value of minimum lease payments for certain contracts currently classified as operating leases will result in increases to assets, liabilities, depletion, depreciation and amortization, and finance expense, and a decrease to production and transportation expenses upon implementation. Cash flows associated with lease repayments will be allocated between operating and financing activities based on their interest repayment and principal repayment portions. An optional exemption to not recognize certain short-term leases and leases of low value can be applied by lessees. For lessors, the accounting remains essentially unchanged. The standard will be effective for the Company on January 1, 2019.

The Company has developed a plan to identify and review its various lease agreements in order to determine the impact that adoption of IFRS 16 will have on the financial statements. The Company is currently completing its review and analysis of the significant lease contracts that fall into the scope of the new standard. The Company expects adjustments for surface land rights, certain leased vehicles and field equipment; however, the full extent of the impact has not yet been finalized as the Company has not completed reviewing all of the contracts that it has in place.

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 December 31, 2018, 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:

	December 31, 2018	December 31, 2017
Accounts receivable		
Marketing receivables	**$ 168,284**	$ 1,284,474
Trade receivables	**$ 104,454**	$ 76,437
Receivables from joint ventures	**14,431**	7,297
Reclamation deposits	**115,535**	115,535
	$ 402,704	$ 1,483,743

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 December 31, 2018, the Company had net debt (current assets less current liabilities excluding fair value of financial instruments, less the gross term loan) of $35,446,384 (December 31, 2017 - $18,558,361), which includes the gross term loan of $35,458,800 (December 31, 2017 - $18,868,500). The Company funds its operations through operating cash flows and the term loan, which includes proceeds drawn of $13,746,745 (2017 - $17,302,753) net of issue costs. At December 31, 2018, the Company has an additional US$4 million of borrowing base committed with its lender, which it can draw for future capital programs.

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 $355,000 annual effect on net loss.

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. The Company does have foreign currency mark-to-market swaps in place as further disclosed within this MD&A and the audited annual financial statements for the year ended December 31, 2018; 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 $240,000 effect on the annual net loss and comprehensive 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 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 audited annual financial statements for the year ended December 31, 2018.

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 (used in) 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 funds flow from (used in) 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 (used in) 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 (used in) 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 (used in) operations to cash provided by (used in) operating activities is presented as follows:

	Three Months Ended December 31		Year Ended December 31	
	2018	2017	**2018**	2017
Cash provided by operating Activities	**$ 231,078**	$ 166,399	**$ 2,230,071**	$ 1,915,248
Change in non-cash working capital	**956,509**	(548,402)	**217,224**	(560,801)
Funds flow from (used in) Operations	**$ (725,431)**	$ 714,801	**$ 2,012,847**	$ 2,476,049
Per share, basic and diluted	**$ (0.01)**	$ 0.01	**$ 0.02**	$ 0.03

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.

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.

c) 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, less 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 December 31	
	2018	2017
Current assets[1]	**$ 2,258,590**	$ 2,955,446
Current liabilities[1]	**(2,246,174)**	(2,645,307)
Gross term loan[2]	**(35,458,800)**	(18,868,500)
Net debt	**$ (35,446,384)**	$ (18,558,361)

Notes:

(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.

Analogous Information

The information concerning analogue pools in this MD&A (particularly in the Message to Shareholders, included with the Annual Report) may be considered to be "analogous information" within the meaning of applicable securities laws. Such information was obtained by Hemisphere management throughout the year ended December 31, 2018 from various public sources including information available to Hemisphere through the Alberta Energy Regulator. Management believes that the performance of such pools is analogous to the pools in which the Company has an interest at its Atlee Buffalo property area and is relevant as it may help to demonstrate the reaction of such pools to waterflood stimulations. Hemisphere is unable to confirm whether the analogous information was prepared by a qualified reserves evaluator or auditor or in accordance with National Instruments 51-101 – Standards of Disclosure for Oil and Gas Activities and the COGE Handbook and therefore, the reader is cautioned that the data relied upon by

Hemisphere may be in error and/or may not be analogous to the oil pools in which Hemisphere holds an interest.

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.

MANAGEMENT'S REPORT

To the Shareholders of Hemisphere Energy Corporation:

Management is responsible for the preparation of the financial statements and the consistent presentation of all other financial information that is publicly disclosed. The financial statements have been prepared in accordance with the accounting policies detailed in the notes to the financial statements and in accordance with IFRS and include estimates and assumptions based on management's best judgment. Management maintains a system of internal controls to provide reasonable assurance that assets are safeguarded and that relevant and reliable financial information is produced in a timely manner. Independent auditors appointed by the shareholders have examined the financial statements. Their report is presented with the financial statements. The Audit Committee, consisting of independent members of the Board of Directors, has reviewed the financial statements with management and the independent auditors. The Board of Directors has approved the financial statements on the recommendation of the Audit Committee.

Vancouver, British Columbia
April 24, 2019

(signed) *"Don Simmons"*
Don Simmons, President & CEO

(signed) *"Dorlyn Evancic"*
Dorlyn Evancic, Chief Financial Officer

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Hemisphere Energy Corporation,

Opinion

We have audited the financial statements of Hemisphere Energy Corporation (the "Entity"), which comprise:

- the statements of financial position as at December 31, 2018 and December 31, 2017
- the statements of loss and comprehensive loss for the years then ended
- the statements of changes in shareholders' equity for the years then ended
- the statements of cash flows for the years then ended
- and notes to the financial statements, including a summary of significant accounting policies.

(hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2018 and December 31, 2017, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards ("IFRS").

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the ***"Auditors' Responsibilities for the Audit of the Financial Statements"*** section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Other Information

Management is responsible for the other information. Other information comprises:

- the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions.

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions as at the date of this auditors' report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditors' report.

We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.
- The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained

up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.
- Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

The engagement partner on the audit resulting in this auditors' report is John Waiand.

KPMG LLP

Chartered Professional Accountants

Calgary, Canada
April 24, 2019

STATEMENTS OF FINANCIAL POSITION

(Expressed in Canadian dollars)

	Note	**December 31, 2018**	December 31, 2017
Assets			
Current assets			
Cash and cash equivalents		**$ 1,780,658**	$ 1,372,991
Accounts receivable		**287,169**	1,368,208
Prepaid expenses		**190,762**	214,247
Fair value of financial instruments	5(c)	**636,801**	-
		2,895,390	2,955,446
Non-current assets			
Reclamation deposits	10	**115,535**	115,535
Fair value of financial instruments	5(c)	**219,175**	-
Exploration and evaluation assets	8	**3,195,215**	4,894,108
Property and equipment	9	**52,226,110**	39,894,023
Deferred charges	12	**546,063**	1,210,691
Total assets		**$ 59,197,488**	$ 49,069,803
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**$ 2,246,175**	$ 2,645,307
Fair value of financial instruments		**-**	1,579,726
		2,246,175	4,225,033
Non-current liabilities			
Term loan	12	**33,323,584**	17,465,518
Fair value of financial instruments		**-**	843,556
Decommissioning obligations	10	**7,756,866**	6,176,112
		43,326,625	28,710,219
Shareholders' Equity			
Share capital	13	**54,724,441**	54,724,441
Contributed surplus		**1,014,623**	649,775
Warrant reserve	13(c)	**1,043,136**	1,043,136
Deficit		**(40,911,337)**	(36,057,768)
Total shareholders' equity		**15,870,863**	20,359,584
Total liabilities and shareholders' equity		**$ 59,197,488**	$ 49,069,803

Commitments (Note 15)

Subsequent events (Note 18)

The accompanying notes are an integral part of these financial statements.

Approved by the Board of Directors

(signed) *"Bruce McIntyre"*
Bruce McIntyre, Director

(signed) *"Don Simmons"*
Don Simmons, Director

STATEMENTS OF LOSS AND COMPREHENSIVE LOSS

(Expressed in Canadian dollars)

	Note		Years Ended December 31 2018		2017
Revenue					
Oil and natural gas revenue	7	$	**17,756,439**	$	10,974,634
Royalties			**(3,081,225)**		(1,817,607)
			14,675,214		9,157,027
Realized loss on financial instruments			**(2,644,783)**		(18,654)
Unrealized (loss) gain on financial instruments	5(c)		**3,279,258**		(2,423,282)
Net revenue			**15,309,689**		6,715,091
Expenses					
Production and operating			**5,614,899**		4,225,131
Exploration and evaluation	8		**932,374**		576,586
Depletion and depreciation	9		**4,460,900**		3,097,839
General and administrative			**1,875,256**		1,584,837
Share-based payments	13(b)		**263,235**		233,508
Impairment of property and equipment	9		**1,574,872**		-
			14,721,536		9,717,901
Results from operating activities			**588,153**		(3,002,810)
Finance expense	11		**(3,298,569)**		(1,078,380)
Foreign exchange gain (loss)			**(2,143,153)**		(262,731)
Loss before tax			**(4,853,569)**		(4,343,921)
Deferred tax recovery	17		**-**		547,746
Net loss and comprehensive loss for the Year		**$**	**(4,853,569)**	$	(3,796,175)
Net loss per share, basic and diluted	13(d)	**$**	**(0.05)**	$	(0.04)

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(Expressed in Canadian dollars)

	Note	Number of common shares		Share Capital		Contributed Surplus		Warrant Reserve		Deficit		Total Equity
Balance, December 31, 2016		**85,745,102**	**$**	**53,838,621**	**$**	**1,192,106**	**$**	**-**	**$**	**(33,136,591)**	**$**	**21,894,136**
Flow-through share issuance		4,048,200		1,133,496		-		-		-		1,133,496
Share issuance costs		-		(85,748)		-		-		-		(85,748)
Flow-through share premium		-		(161,928)		-		-		-		(161,928)
Share-based payments	13(b)	-		-		332,669		-		-		332,669
Expiry of stock options		-		-		(875,000)		-		875,000		-
Warrant Issue – net deferred tax	13(c)	-		-		-		1,043,136		-		1,043,136
Net loss for the year		-		-		-		-		(3,796,175)		(3,796,175)
Balance, December 31, 2017		**89,793,302**	**$**	**54,724,441**	**$**	**649,775**	**$**	**1,043,136**	**$**	**(36,057,768)**	**$**	**20,359,584**
Balance, December 31, 2017		**89,793,302**	**$**	**54,724,441**	**$**	**649,775**	**$**	**1,043,136**	**$**	**(36,057,768)**	**$**	**20,359,584**
Share-based payments	13(b)	-		-		364,848		-		-		364,848
Net loss for the year		-		-		-		-		(4,853,569)		(4,853,569)
Balance, December 31, 2018		**89,793,302**		**54,724,441**		**1,014,623**		**1,043,136**		**(40,911,337)**		**15,870,863**

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CASH FLOWS
(Expressed in Canadian dollars)

		Years Ended December 31		
		2018		2017
Operating activities				
Net loss for the year	**$**	**(4,853,569)**	$	(3,796,175)
Items not affecting cash:				
Accretion of debt issuance costs		**293,681**		48,738
Accretion of decommissioning costs		**138,345**		107,727
Amortization of deferred charges		**202,332**		87,837
Deferred tax recovery		**-**		(547,746)
Depletion and depreciation		**4,460,900**		3,097,839
Exploration and evaluation expense		**932,374**		576,586
Share-based payments		**263,235**		233,508
Unrealized loss (gain) on financial instruments		**(3,279,258)**		2,423,282
Unrealized loss on foreign exchange		**2,279,935**		244,453
Impairment		**1,574,872**		-
		2,012,847		2,476,049
Changes in non-cash working capital		**217,224**		(560,801)
Cash provided by operating activities		**2,230,071**		1,915,248
Investing activities				
Property and equipment expenditures		**(12,398,208)**		(4,580,698)
Exploration and evaluation expenditures		**(3,659,109)**		(4,108,542)
Changes in non-cash working capital		**488,168**		1,044,020
Cash used in investing activities		**(15,569,149)**		(7,645,220)
Financing activities				
Shares issued for cash, net of issue costs		**-**		1,047,748
Change in bank indebtedness		**-**		(11,247,537)
Proceeds from term loan (net of issue costs – Note 12)		**13,746,745**		17,302,753
Changes in non-cash working capital		**-**		-
Cash provided by financing activities		**13,746,745**		7,102,964
Net change in cash		**407,667**		1,372,991
Cash, beginning of year		**1,372,991**		-
Cash, end of year	**$**	**1,780,658**	$	1,372,991

Supplemental cash flow information (Note 16)

The accompanying notes are an integral part of these financial statements.

NOTES TO THE FINANCIAL STATEMENTS

For the years ended December 31, 2018 and December 31, 2017

(Expressed in Canadian dollars)

1. Nature and Continuance of Operations

Hemisphere Energy Corporation (the "Company") was incorporated under the laws of British Columbia on March 6, 1978. The Company's principal business is the acquisition, exploration, development and production of petroleum and natural gas interests in Canada. It is a publicly traded company listed on the TSX Venture Exchange under the symbol "HME". The Company's head office is located at Suite 501, 905 Pender Street West, Vancouver, British Columbia, Canada V6C 1L6. The Company has no subsidiaries.

2. Basis of Presentation

(a) Statement of compliance

These audited annual financial statements ("Financial Statements") have been prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB").

These Financial Statements were authorized for issuance by the Board of Directors on April 24, 2019.

(b) Basis of presentation

These Financial Statements have been prepared on a historical cost basis, except for certain financial instruments and share-based payments, which are stated at their fair values. These policies have been applied consistently for all periods presented, other than as described in note 3.

(c) Functional and presentation currency

These Financial Statements are presented in Canadian dollars, which is the Company's functional currency.

(d) Use of estimates and judgments

The preparation of these Financial Statements in conformity with IFRS requires management to make judgments, estimates and assumptions that may affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may materially differ from these estimates.

Estimates and their underlying assumptions are reviewed on an ongoing basis and are based on management's experience and other factors, including expectation of future events that are believed to be reasonable under the circumstances. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Reserve estimation including engineering data, geological and geophysical data, projected future rates of production, commodity pricing, operating costs and timing of future expenditures, are subject to significant judgment and interpretation. These estimates are a critical part of many of the estimated amounts and calculations contained in the financial statements. These estimates are verified by third party professional engineers, who work with information provided by the Company to establish reserve determinations. These determinations are updated at least on an annual basis.

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. See further discussions relating to liquidity in Note 5.

Significant areas of estimation, uncertainty and critical judgments in applying accounting policies that have the most significant effect on the amount recognized in the financial statements include:

(i) Impairment testing – internal and external sources of information including petroleum and natural gas prices, expected production volumes, anticipated recoverable quantities of proved and probable reserves and rates used to discount future cash flow estimates. Judgement is required to assess these factors when determining if the carrying amount of an asset is impaired, or in the case of previously impaired asset, whether the carrying amount of the asset has been restored.

(ii) Depletion and depreciation – oil and natural gas reserves, including future prices, costs and reserve base to use on calculation of depletion.

(iii) Decommissioning obligations – estimates relating to amounts, likelihood, timing, inflation and discount rates.

(iv) Share-based payments – expected life of the options, risk-free rate of return and stock price volatility

(v) Determinations of cash generating units ("CGUs") – geographic location, commodity type, reservoir characteristics and lowest level of cash inflows.

(vi) Determining the technical feasibility and commercial viability of exploration and evaluation assets.

(vii) Business combinations - estimates of the fair value of assets acquired and liabilities assumed which includes assessing the value of petroleum and natural gas properties based upon the estimation of recoverable quantities of Proved and Probable reserves being acquired

(viii) Provisions - exercise of significant judgment and estimates of the outcome of future events.

(ix) Deferred tax asset – the amounts recorded for deferred tax assets are based on estimates as to the timing of the reversal of temporary differences, substantially enacted tax rates, and the likelihood of tax assets being realized. The availability of tax pools and other deductions are subject to audit and interpretation by tax authorities.

3. Significant Accounting Policies

(a) Revenue

The Company has adopted IFRS 15 effective January 1, 2018 and applied IFRS 15 to all of its contracts with customers using the modified respective method. Under this method, prior period financial statements have not been restated. Management reviewed the Company's revenue streams and major contracts with customers using the IFRS 15 principles-based five-step model and concluded there were no material changes to earnings or in the timing of when production revenue is recognized. As a result, no adjustments were required in the January 1, 2018 opening balance sheet.

The adoption of IFRS 15 results in new disclosure requirements contained in note 7 of these audited financial statements. The Company primarily earns revenue from sales of the production of light oil, heavy oil, natural gas and natural gas liquids. The Company may earn revenue from fees charged to third parties for processing and other services (i.e., gas and other product processing, etc.) provided at locations where the Company has processing facilities, however, the Company does not currently conduct any third party processing.

Revenues from the sale of crude oil, natural gas liquids and natural gas is recognized based on the consideration specified in contracts with customers. The Company recognizes revenue when it transfers control of the product to the customer, which is generally when legal title passes to the customer which is when it is physically transferred to the pipeline or other transportation method agreed upon and collection is reasonably assured. Any revenues from processing activities are recognized over time as processing occurs, and are generally billed monthly.

The Company evaluates its arrangements with third parties and partners to determine if the Company is acting as the principal or as an agent. The Company is considered the principal in a transaction when it has primary responsibility for the transaction. If the Company acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net basis, only reflecting the fee, if any, realized by the Company from the transaction.

(b) Jointly owned assets

Some of the Company's petroleum and natural gas activities involve jointly owned assets and are conducted under joint operating agreements. Accordingly the financial statements reflect the Company's proportionate share of joint assets, liabilities, revenues and expenses.

(c) Property and equipment and exploration and evaluation assets

(i) Pre-exploration expenditures

Expenditures made by the Company before acquiring the legal right to explore in a specific area do not meet the definition of an asset and therefore are expensed as incurred.

(ii) Exploration and evaluation expenditures

Costs incurred once the legal right to explore has been acquired are capitalized as exploration and evaluation assets. These costs include, but are not limited to, exploration license expenditures, leasehold property acquisition costs, evaluation costs, drilling costs directly attributable to an identifiable well, and directly attributable general and administrative costs. These costs are accumulated in cost centers by property and are not subject to depletion until technical feasibility and commercial viability has been determined.

Exploration and evaluation assets are assessed for impairment at each reporting date when facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

The technical feasibility and commercial viability are considered to be determinable when Proved and Probable reserves have been identified. A review of each exploration license or field is carried out quarterly to ascertain whether Proved and Probable reserves have been discovered. Upon determination of Proved and Probable reserves, exploration and evaluation assets attributable to those reserves are tested for impairment and reclassified from exploration and evaluation assets to petroleum and natural gas properties.

(iii) Property and equipment

Items of property and equipment, which include petroleum and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and impairment losses.

Gains and losses on disposal of an item of property and equipment, including petroleum and natural gas properties, are determined by comparing the proceeds from disposal with the carrying amount of property and equipment and are recognized in profit or loss.

(iv) Capitalization of costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property and equipment are recognized as petroleum and natural gas properties only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such capitalized petroleum and natural gas properties generally represent costs incurred in developing Proved and/or Probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property and equipment are recognized in profit or loss as incurred.

(v) Depletion and depreciation

Depletion of petroleum and natural gas properties is determined using the unit-of-production method based on production volumes in relation to total estimated Proved and Probable reserves as determined annually by independent engineers and determined in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities. Natural gas reserves and production are converted at the energy equivalent of six thousand cubic feet to one barrel of oil.

The calculation of depletion and depreciation is based on total capitalized costs plus estimated future development costs of Proved and Probable non-producing and undeveloped reserves.

Proved and probable reserves are estimated using independent reserve engineer reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids, which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. There should be a 50 percent statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as Proved and Probable and a 50 percent statistical probability that it will be less. The equivalent statistical probabilities for the proved component of Proved and Probable reserves are 90 percent and 10 percent, respectively.

Such reserves may be considered commercially viable if management has the intention of developing and producing them. Such intention is based upon:

- A reasonable assessment of the future economics of such production;
- A reasonable expectation that there is a market for all or substantially all the expected oil and natural gas production; and
- Evidence that the necessary production, transmission and transportation facilities are available or can be made available.

Reserves may only be considered Proved if supported by either actual production or conclusive formation tests. The area of reservoir considered Proved includes (a) that portion delineated by drilling and defined by as-oil and/or oil-water contacts, if any, or both, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geophysical, geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of oil and natural gas controls the lower Proved limit of the reservoir.

Reserves that can be produced economically through application of improved recovery techniques such as fluid injection are only included in the Proved classification when successful testing by a pilot project, the operation of an installed program in the reservoir or other reasonable evidence (such as, experience of the dame techniques on similar reservoirs or reservoir simulation studies) provides support for the engineering analysis on which the project or program was based.

Depreciation of other equipment is provided for on a 20-30% declining balance basis. Depreciation methods, useful lives and residual values are reviewed at each reporting date.

(vi) Impairment

Exploration and evaluation assets are grouped together with the Company's CGUs when they are assessed for impairment, both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to developed and producing assets (petroleum and natural gas properties).

Exploration and evaluation assets are assessed for impairment when they are reclassified to developing and producing assets, as part of the petroleum and natural gas properties, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For developed and producing assets, an impairment is recorded when the recoverable amount of a CGU is less than the respective carrying amount. Recoverable amount is the higher of its fair value less cost to sell and value in use. Fair value is the price that would be received from selling an asset in an orderly transaction between market participants. Fair value less costs to sell can be determined by using observable market information or by using discounted future net cash flows of Proved and Probable reserves using forecasted prices and costs. Value in use is determined by estimating the present value of the future net cash flows expected to be derived from the continued use of the asset or CGU.

Judgment is required to assess when indicators of impairment or reversals exist and whether calculation of the recoverable amount of an asset is necessary. Management considers internal and external sources of information including petroleum and natural gas prices, expected production volumes, anticipated recoverable quantities of proved and probable reserves and rates used to discount future cash flow estimates. Judgement is required to assess these factors when determining if the carrying amount of an asset is impaired, or in the case of previously impaired asset, whether the carrying amount of the asset has been restored.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. A CGU's recoverable amount is the higher of its fair value less costs to sell and its value in use. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of goodwill, if any, allocated to the units and then to reduce carrying amounts of other assets in the unit (group of units) on a pro rata basis.
Impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been

determined, net of depletion and depreciation, if no impairment loss had been recognized.

(d) Decommissioning obligations

Decommissioning obligations are measured at the present value of management's best estimate of expenditures required to settle the present obligation at the reporting date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is included as finance expense whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision.

(e) Share-based payments

The Company has a stock option plan that is described in Note 13(b). Share-based payments to employees are measured at the fair value of the instruments issued and are amortized over the vesting periods. The offset to the recorded cost is to Company's contributed surplus.

Consideration received on the exercise of stock options is recorded as share capital and the related contributed surplus is transferred to capital stock. Charges for options that are forfeited before vesting are reversed from contributed surplus. For those options that expire after vesting, the recorded value is transferred to deficit.

(f) Share Capital and warrants

The Company uses the fair value method for valuing stock options, restricted and performance share awards, performance warrants and warrants. Under the fair value method, compensation costs attributable to all stock options, restricted and performance share awards, performance warrants and warrants granted are measured at fair value at the date of grant and expensed over the vesting period with a corresponding increase to contributed surplus or warrants. A forfeiture rate is estimated on the date of grant and is adjusted to reflect the actual number of awards that vest. Performance share awards are also subject to a performance multiplier that is adjusted to reflect the final number of awards. The fair value of each option, performance warrant or warrant granted is estimated using the Black-Scholes option pricing model that takes into account the grant date, the exercise price and expected life of the option, performance warrant or warrant, the price of the underlying security, the expected volatility, the risk-free interest rate and dividends, if any, on the underlying security. The fair value of each restricted and performance share award is determined with reference to the trading price of the Company's common shares on the date of grant. Upon the exercise of the stock options, restricted and performance share awards, performance warrants and warrants, consideration received together with the amount previously recognized in contributed surplus or warrants is recorded as an increase to share capital and the contributed surplus or warrants balance is reduced.

Incremental costs directly attributable to the issue of common shares, warrants and share options are recognized as a deduction from equity, net of any tax effects.

(g) Flow-through shares and units

The Company, from time to time, may issue flow-through common shares to finance a portion of its petroleum and natural gas exploration activities. Canadian income tax law permits the Company to renounce to the flow-through shareholders the income tax attributes of certain petroleum and natural gas exploration and evaluation costs financed by such shares. A liability is recognized for any premium on the flow-through shares in excess of a regular common share and is subsequently reversed as the Company incurs qualifying the designated Canadian exploration or development expenses.

(h) Income taxes

Income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss, except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current income tax expense is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred income tax is recognized using the balance sheet liability method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred income tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred income tax assets and liabilities are offset if there is a legally enforceable right to offset and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred income tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(i) Per share amounts

Basic per share amounts are calculated by dividing the income or loss attributable to common shareholders of the Company by the weighted-average number of common shares outstanding during the period. Diluted income or loss per share is determined by dividing the income or loss attributable to common shareholders by the weighted-average number of shares outstanding adjusted for the effects of dilutive instruments such as options and warrants.

The Company uses the treasury stock method to compute the dilutive effect of stock options and warrants. Under this method the dilutive effect on earnings per share is calculated presuming the exercise of outstanding stock options and warrants. It assumes that proceeds received from the exercise of stock options and warrants would be used to repurchase common shares at the average market price during the year. However, the calculation of diluted loss per share excludes the effects of various conversions and exercise of options and warrants that would be anti-dilutive.

(j) Changes in accounting policies

i) IFRS 15 - In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers," which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts," and related interpretations. The standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2018. The new standard provides a single, principles-based five-step analysis of transactions to determine the nature of an entity's obligation to perform and whether, how much and when revenue is recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized.

ii) IFRS 9 - In July 2014, the IASB finalized the remaining elements of IFRS 9 – Financial Instruments, which includes new requirements for the classification and measurement of financial assets, amends the impairment model and outlines a new general hedge accounting standard.

On January 1, 2018, the Company adopted all of the requirements of IFRS 9, “Financial Instruments” (“IFRS 9”) which replaces IAS 39, “Financial Instruments: Recognition and Measurement” (“IAS 39”). The adoption of IFRS 9 had no material impact to the Company’s financial statements.

IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost; fair value through other comprehensive income (“FVOCI”); or fair value through profit or loss (“FVTPL”). The classification of financial assets under IFRS 9 is generally based on the business model in which a financial asset is managed and its contractual cash flow characteristics. IFRS 9 eliminates the previous IAS 39 categories of held to maturity, loans and receivables and available for sale. IFRS 9 largely retains the existing requirements in IAS 39 for the classification of financial liabilities.

The following table shows the original measurement categories under IAS 39 and the new measurement categories under IFRS 9 as at January 1, 2018 for each class of the Company’s financial assets and financial liabilities:

	Measurement category	
Financial instrument	IAS 39	IFRS 9
Cash and cash equivalents	Loans and receivables	Amortized cost
Accounts receivable	Loans and receivables	Amortized cost
Financial derivative contracts	Fair value via profit or loss	Fair value via profit or loss
Accounts payable and accrued liabilities	Financial liabilities at amortized cost	Amortized cost
Term loan	Financial liabilities at amortized cost	Amortized cost

There were no adjustments to the carrying amounts of the Company's financial instruments as a result of the change in classification from IAS 39 to IFRS 9. The Company does not apply hedge accounting.

IFRS 9 replaces the "incurred loss" model in IAS 39 with an "expected credit loss" ("ECL") model. The Company measures loss allowances at an amount equal to expected lifetime ECLs. Lifetime ECLs are the anticipated ECLs that result from all possible default events over the expected life of a financial asset. ECLs are a probability-weighted estimate of credit loss and are discounted at the effective interest rate of the related financial asset. The application of the new expected credit loss model did not have a significant impact on the Company's financial assets.

k) Future accounting pronouncements

At the date of these financial statements the standards and interpretations listed below were issued but not yet effective. The adoption of these standards may result in future changes to existing accounting policies and disclosures. The Company is currently evaluating the impact that these standards will have on results of operations and financial position.

IFRS 16 - In January 2016, the IASB issued IFRS 16 Leases, which replaces the current IFRS guidance on leases under IAS 17. Under the current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the balance sheet, while operating leases are recognized in profit or loss when the expense is incurred.

Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. The recognition of the present value of minimum lease payments for certain contracts currently classified as operating leases will result in increases to assets, liabilities, depletion, depreciation and amortization, and finance expense, and a decrease to production, operating and transportation expenses upon implementation. Cash flows associated with lease repayments will be allocated between operating and financing activities based on their interest repayment and principal repayment portions. An optional exemption to not recognize certain short-term leases and leases of low value can be applied by lessees. For lessors, the accounting remains essentially unchanged.

The standard will be effective for the Company on January 1, 2019. The Company is currently evaluating the impact of adopting IFRS 16 on the Company's financial statements and is in the final stage of gathering and analyzing contracts that will fall into scope of this standard. The Company expects adjustments for surface land rights, certain leased vehicles and field equipment; however, the full extent of the impact has not yet been finalized as the Company has not completed reviewing all of the contracts that it has in place.

There are no other standards and interpretations in issue but not yet adopted that are expected to have a material effect on the reported earnings or net assets of the Company.

4. 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 December 31, 2018, 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, which approximates the carrying value.

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.

5. Financial Risk Management

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production and financing activities such as credit risk, liquidity risk and market risk. This note presents information about the Company's exposure to each of these risks. Management sets controls to manage such risks and monitors them on an ongoing basis pertaining to market conditions and the Company's activities.

(a) 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:

		December 31, 2018		December 31, 2017
Accounts receivable				
Marketing receivables	**$**	**168,284**	$	1,284,474
Trade receivables	**$**	**104,454**	$	76,437
Receivables from joint ventures		**14,431**		7,297
Reclamation deposits		**115,535**		115,535
	$	**402,704**	$	1,483,743

The Company sells the majority of its oil production through one 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 any of its marketers.

(b) 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 December 31, 2018, the Company had net debt (current assets less current liabilities excluding fair value of financial instruments, and outstanding term loan) of $35,446,384 (December 31, 2017 - $18,558,361). The Company funds its operations through operating cash flows and the term loan, which included proceeds drawn of $13,746,745 (2017 - 17,302,753) net of issue costs. At December 31, 2018, the Company has an additional US$4 million of borrowing base committed with its lender, which it can draw for future capital programs.

(c) Market risk

Market risk is the risk that changes in market prices, such as foreign exchange rates, other 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.

(i) 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 $355,000 effect on net loss.

(ii) 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 is denominated in USD, and as 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 100 basis points change in the foreign exchange rate would have a $240,000 effect on the annual net loss.

(iii) 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 does have hedging swap agreements in place as further disclosed herein.

At December 31, 2018, the Company held derivative commodity contracts as follows:

Product	**Type**	**Volume**	**Price**	**Index**	**Term**	**Dec. 31, 2018 Fair Value**
Crude oil	Swaption	150 bbl/d	US$54.65	WTI-NYMEX	July 1, 2018 – February 28, 2019	108,442
Crude oil	Swap	250 bbl/d	US$19.20	WCS	January 1, 2019 – March 31,2019	(14,106)
Crude oil	Swap	200 bbl/d	US $18.10	WCS	February 1, 2019 – March 31,2019	22,939
Crude oil	Swap	250 bbl/d	US$50.67	WTI-NYMEX	January 1, 2019 – December 31, 2019	418,910
Crude oil	Collar	130 bbl/d	US$40.00-US$74.50	WTI-NYMEX	March 1, 2019 – December 31, 2019	100,616
Crude oil	Swap	200 bbl/d	US$50.67	WTI-NYMEX	January 1, 2020 – August 31, 2020	106,961
Crude oil	Collar	120 bbl/d	US$40.00-US$68.25	WTI-NYMEX	January 1, 2020 – December 31, 2020	93,208
Crude oil	Collar	200 bbl/d	US$40.00-US$67.05	WTI-NYMEX	September 1, 2020 – December 31, 2020	42,525
Crude oil	Collar	275 bbl/d	US$40.00-US$65.50	WTI-NYMEX	January 1, 2021 – March 31, 2021	(23,519)
					Total	$855,976

At December 31, 2018, the commodity contracts were fair valued as an asset of $855,976 and an unrealized gain of $3,279,258 for the year ended December 31, 2018.

At December 31, 2017, the Company held derivative commodity contracts as follows:

Product	**Type**	**Volume**	**Price**	**Index**	**Term**	**Dec. 31, 2017 Fair Value**
Crude oil	Swap	150 bbl/d	US$54.65	WTI-NYMEX	November 1, 2017 – June 30, 2018	(188,617)
Crude oil	Swap	300 bbl/d	US$50.67	WTI-NYMEX	January 1, 2018 – December 31, 2018	(1,189,728)
Crude oil	Option	150 bbl/d	US$54.65	WTI-NYMEX	July 1, 2018 – February 28, 2019	(255,121)
Crude oil	Swap	250 bbl/d	US$50.67	WTI-NYMEX	January 1, 2019 – December 31, 2019	(595,793)
Crude oil	Swap	200 bbl/d	US$50.67	WTI-NYMEX	January 1, 2020 – August 1, 2020	(194,024)
					Total	$(2,423,282)

At December 31, 2017, the commodity contracts were fair valued as a liability of $2,423,282 and an unrealized loss of $2,423,282 for the year ended December 31, 2017.

(iv) Other price risk

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

6. Capital Management

The Company manages its capital with the following objectives:

(a) To ensure sufficient financial 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

(b) To maximize shareholder return through enhancing the Company's share value.

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, obtaining additional financing from the Company's 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. There were no changes to capital management during the year.

7. Revenue

The Company sells its production pursuant to variable-price contracts. The transaction price for variable-price contracts is based on a benchmark commodity price, adjusted for quality, location or other factors whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under the contracts, the Company is required to deliver variable volumes of heavy oil, natural gas or natural gas liquids to the contract counterparty.

Production revenue is recognized when the Company gives up control of the unit of production at the delivery point agreed to under the terms of the contract. The amount of production revenue recognized is based on the agreed transaction price and the volumes delivered. Any variability in the transaction price relates specifically to the Company's efforts to transfer production and therefore the resulting revenue is allocated to the production delivered in the period to which the variability relates. The Company does not have any factors considered to be constraining in the recognition of revenue with variable pricing factors. Production revenues are normally collected on the business day nearest the 25th day of the month following production.

The Company's production revenues were primarily generated in its core areas of the Mannville oil play in the Atlee Buffalo and Jenner areas of southeastern Alberta. The Company's customers are oil and natural gas marketers and joint operations partners in the oil and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by management's policies and practices related to credit risk as discussed in note 5(a). As at December 31 2018, production revenue sold to customers was comprised primarily from three marketers which account for $162,699 of the accounts receivable balance.

The following table presents the Company's total revenues disaggregated by revenue source:

	Year Ended December 31	
	2018	2017
Oil	**$ 17,539,990**	$ 10,715,271
Natural gas	**184,511**	229,682
NGL	**31,938**	29,679
Total	**$ 17,756,439**	$ 10,974,634

8. Exploration and Evaluation Assets

Exploration and evaluation assets consist of the Company's exploration projects, which are pending the determination of Proved and Probable reserves. A transfer from exploration and evaluation assets to property, plant and equipment is made when reserves are assigned or the exploration project has been completed. For the year ended December 31, 2018, the Company transferred $3,910,309 (December 31, 2017 - $1,898,255) to property, plant and equipment, capitalized general and administrative expenses of $173,487 (December 31, 2017 - $157,564) to exploration and evaluation assets, and recognized exploration and evaluation expense of $932,374 (December 31, 2017 - $576,586), which relate to expired or uneconomic properties.

Cost		
Balance, December 31, 2016	$	3,260,407
Additions		4,108,542
Exploration and evaluation expense		(576,586)
Transfer to property, plant and equipment		(1,898,255)
Balance, December 31, 2017	$	4,894,108
Additions		3,659,109
Exploration and evaluation expense		(932,374)
Transfer to property, plant and equipment		(4,425,628)
Balance, December 31, 2018	**$**	**3,195,215**

9. Property, Plant and Equipment

		Petroleum and Natural Gas		Other Equipment		Total
Cost						
Balance, December 31, 2016	$	67,142,548	$	114,492	$	67,257,040
Additions		4,580,698		-		4,580,698
Decrease in decommissioning obligations		1,171,705		-		1,171,705
Capitalized share-based payments		99,161		-		99,161
Transfer from exploration and evaluation assets		1,898,255		-		1,898,255
Balance, December 31, 2017	$	74,892,367	$	114,492	$	75,006,859
Additions		12,398,208		-		12,398,208
Change in decommissioning obligations		1,442,408		-		1,442,408
Capitalized share-based payments		101,614		-		101,614
Transfer from exploration and evaluation assets		4,425,628		-		4,425,628
Balance, December 31, 2018	**$**	**93,260,225**	**$**	**114,492**	**$**	**93,374,716**
Accumulated Depletion, Depreciation, Amortization and Impairment						
Balance, December 31, 2016	$	31,929,680	$	85,316	$	32,014,996
Depletion and depreciation for the year		3,090,462		7,377		3,097,839
Balance, December 31, 2017	$	35,020,142	$	92,693	$	35,112,835
Depletion and depreciation for the year		4,455,420		5,480		4,460,900
Impairment Loss		1,574,872		-		1,574,872
Balance, December 31, 2018	**$**	**41,050,434**	**$**	**98,173**	**$**	**41,148,607**
Net Book Value						
December 31, 2017	$	39,872,225	$	21,799	$	39,894,023
December 31, 2018	**$**	**52,209,791**	**$**	**16,319**	**$**	**52,226,110**

The Company's additions for property, plant and equipment included capitalized general and administrative expenses of $336,301 and $228,964 for the years ended December 31, 2018 and 2017, respectively.

The calculation for depletion at December 31, 2018 includes estimated future development costs of $50,819,300 (December 31, 2017 - $34,424,000) associated with the development of the Company's Proved plus Probable reserves.

At December 31, 2018, the Company performed an assessment of potential impairment indicators on each of its CGUs, and management determined that an impairment test on its petroleum and natural gas assets was required due to volatile and low commodity prices. It was determined that the carrying amount of Jenner exceeded its recoverable value of $11,682,760 for the year ended December 31, 2018 (year ended December 31, 2017 - $16,411,131). Accordingly, the Company recognized an impairment charge of $1,413,268 as at December 31, 2018 (December 31, 2017 - $nil). It was also determined that the Company would impair its three non-core natural gas properties which were not assigned economic reserves. Accordingly, the Company recognized an impairment charge in aggregate of $161,604 for the three natural gas properties as at December 31, 2018 (December 31, 2017 - $nil). No impairment was recognized for Atlee Buffalo as its recoverable value exceeded the carrying amount.

The recoverable amounts 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, loss factors and discount rates specific to the underlying composition of assets residing in each CGU. The pre-tax discount rates ranged from 10% to 15% depending on the nature of the reserves. The following tables show the future commodity price estimates used by the Company's independent reserves evaluator at December 31, 2018:

2018	2019	2020	2021	2022	2023	2024	2025	2026	Thereafter
WTI (US$/bbl)	56.50	63.80	67.60	71.60	73.10	74.50	76.00	77.50	+2%/yr
WCS (C$/bbl)	47.50	58.00	64.40	68.40	69.80	71.20	72.60	74.00	+2%/yr
AECO(Cdn$/MMbtu)	1.85	2.20	2.55	3.05	3.20	3.30	3.35	3.40	+2%/yr

10. Decommissioning Obligations

The Company's decommissioning obligation is estimated based on its net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities, and the estimated timing of the costs to be incurred in future years. The Company uses Alberta Energy Regulator guidelines for determining abandonment and reclamation estimates.

The Company estimates the total undiscounted and inflated amount of cash flows required to settle its decommissioning obligations as at December 31, 2018 is $11,993,913 (December 31, 2017 - $9,912,034). These payments are expected to be made over the next 43 years with the costs to be incurred between 2027 and 2061. The discount factor, being the risk-free rate related to the liability, is 1.92% (December 31, 2017 - 2.24%). Inflation of 2.1% (December 31, 2017 – 1.80%) has also been factored into the calculation of amounts in the table below. The Company also has $115,535 (December 31, 2017 - $115,535) in various reclamation bonds for its properties held by the Alberta Energy Regulator and British Columbia Ministry of Energy, Mines and Petroleum Resources.

The change in estimates for the years ended December 31, 2018 and 2017 resulted from the decommissioning obligations being revalued at the year-end risk-free and inflation rates.

		December 31, 2018		December 31, 2017
Decommissioning obligations, beginning of year	$	6,176,112	$	4,896,681
Increase in estimated future obligations		1,154,722		847,114
Change in estimate		287,687		324,591
Accretion expense		138,345		107,727
Decommissioning obligations, end of year	$	7,756,866	$	6,176,112

11. Finance Expenses

	Year Ended December 31			
		2018		2017
Finance expense:				
Cash Interest expense	$	2,664,211	$	834,078
Amortization of deferred charges		293,681		87,837
Accretion of debt issuance costs		202,332		48,738
Accretion of decommissioning liabilities		138,345		107,727
Total	$	3,298,569	$	1,078,380

12. 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 obtain an increased commitment of 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 December 31, 2018 the Company has drawn US$26.0 million (CAD$35,458,800 - at closing US exchange rate). 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 effective interest rate is 10.66%.

The below table outlines the changes in the term loan and deferred charges compared to the prior year:

	Term Loan		Deferred Charges	
	2018	2017	**2018**	2017
Balance, beginning of year	**$ 17,465,518**	$ -	**$ (1,210,691)**	$ -
Principal amount issued	**14,199,400**	18,530,810		
Foreign exchange adjustment	**2,279,936**	244,453		
Transfer of deferred issuance costs cash	**(534,379)**	(746,074)	**81,724**	(481,983)
Transfer of deferred issuance costs warrants	**(380,573)**	(612,409)	**380,573**	(816,545)
Deferred charges /amortized	**-**	-	**202,332**	87,837
Accretion of debt issuance costs	**293,681**	48,738		
Balance, end of year	**33,323,584**	**17,465,518**	**(546,063)**	(1,210,691)

The Company drew US$11.0 million (CAD$14,199,400) on the term loan in the year (2017 – US$15.0 million; CAD$18,530,810), and incurred additional debt issuance costs of $452,655 (2017 – $1,228,057), for net proceeds of $13,746,745.

The below table summarizes the sum of issuance costs included in both the term loan and deferred charges as at December 31, 2018:

	Term Loan	Deferred Charges	Total
Principal amount of Term Loan issued	$ 32,730,210	$ -	$ 32,730,210
Foreign exchange adjustment	2,524,389	-	2,524,380
Debt issuance costs	(1,280,453)	(400,259)	(1,680,712)
Value allocated to warrants	(992,982)	(435,973)	(1,428,955)
Amortization of deferred charges	-	290,169	290,169
Accretion of debt issuance costs	342,419	-	342,419
Balance, end of year – liability (asset)	**$ 33,323,584**	**$ (546,063)**	**$ 32,777,521**

The Company has recognized a portion of the debt issuance costs and value allocated to the warrants (Note 13(c)) against the Term Loan based on the proportion of the facility drawn, with the balance included in deferred charges. The portion recognized against the Term Loan will be accreted using the effective interest method (refer to effective interest rate above) through finance expense while the deferred charge balance is being straight-line amortized over the five-year term. As future draws are made under the term Loan, the unamortized proportion of the deferred charges will be transferred against the debt obligation and accreted also using the effective interest method.

The Term Loan is subject to certain financial, which are listed below from the fourth quarter ended December 31, 2018 and onward:

1. Interest coverage ratio for the quarter ended December 31, 2018 shall not be less than 2.50 to 1.00; quarter ended March 31, 2019 and each quarter thereafter shall not be less than 3.00 to 1.00. This ratio is calculated using amounts from the reporting quarter only.

   Interest coverage ratio, as defined in the Credit Agreement, means the ratio as of the last day of any fiscal quarter of (a) Adjusted EBITDAX as defined below for the applicable fiscal quarter to (b) Interest Expense for such fiscal quarter.

2. Total leverage ratio for the quarter ended December 31, 2018 shall not be more than 4.25 to 1.00; quarters ended March 31, 2019 and June 30, 2019 shall not be more than 3.50 to 1.00; quarter ended September 30, 2019 and each quarter thereafter shall not be more than 3.25 to 1.00.

   Total leverage ratio, as defined in the Credit Agreement, means the ratio as of the last day of any fiscal quarter of (a) Total Debt as of such date to (b) Adjusted EBITDAX for the fiscal quarter ending on such date calculated on an annualized basis, whereas Adjusted EBITDAX from the reporting quarter is factored by four.

3. The Company also has a financial covenant for its cash general and administrative costs ("G&A costs") that it shall not exceed 105% of the cash costs cap of $2.5 million per annum as at December 31, 2018.

The Term Loan is also subject to certain performance covenants surrounding production and reserves as denoted in the table below. For the quarter ending December 31, 2018 the Company has met its required minimum average production and its general and administrative costs covenants. The two financial covenants (being the interest coverage ratio and total leverage ratio covenants) and two reserve-based covenants (being the PDP coverage ratio and total proved reserve coverage ratio covenants) were waived for the quarter ended December 31, 2018.

Ratio			**Required**	**Actual Dec. 31, 2018**	
1.	Interest Coverage Ratio	Greater than	2.50	Waived	
2.	Total Leverage Ratio	Less than	4.25	Waived	
3.	Minimum Average Production	Greater than	1,100	1,378	Boe/d
4.	Proved Developed Producing Coverage Ratio	Greater than	1.00	Waived	
5.	Total Proved Reserves Coverage Ratio	Greater than	1.50	Waived	
6.	General and Administrative Costs	Less than	$2.65	$2.39	$MM

13. Share Capital

(a) Authorized

Unlimited number of common shares without par value.

Issued and outstanding

As at December 31, 2018, the Company had 89,793,302 (December 31, 2017 – 89,793,302) common shares issued and outstanding.

No shares were issued during the year ended December 31, 2018.

(b) Stock options

The Company has a stock option plan in place and is authorized to grant stock options to officers, directors, employees and consultants whereby the aggregate number of shares reserved for issuance may not exceed 10% of the issued shares at the time of grant and 5% of the issued shares to each optionee. Stock options are non-transferable and have a maximum term of five years. Stock options terminate no later than 90 days (30 days for investor-related services) upon termination of employment or employment contract and one year in the case of retirement, death or disability. The grant price is determined using the closing price of the Company's shares from the day prior to the grant.

Details of the Company's stock options as at December 31, 2018 and 2017 are as follows:

Exercise Price	Grant Date	Expiry Date	Balance Outstanding Dec. 31, 2017	Changes in the Year Granted	Exercised	Expired	Balance Outstanding Dec. 31, 2018	Balance Exercisable Dec. 31, 2018
$0.24	29-Jan-15	29-Jan-20	1,075,000	-	-	-	1,075,000	1,075,000
$0.39	1-Mar-15	1-Mar-20	100,000	-	-	-	100,000	100,000
$0.08	11-Feb-16	11-Feb-21	1,685,000	-	-	-	1,685,000	1,685,000
$0.08	12-Feb-16	12-Feb-21	125,000	-	-	-	125,000	125,000
$0.25	21-Sep-17	21-Sep-22	5,034,000	-	-	-	5,034,000	3,356,000
$0.28	2-Oct-17	2-Oct-22	150,000	-	-	-	150,000	100,000
$0.25	01-Jan-18	01-Jan-23	-	250,000	-	-	250,000	83,333
			8,169,000	250,000	-	-	8,419,000	6,524,333
Weighted-average exercise price			$0.21	$0.25	-	-	$0.21	$0.20

Exercise Price	Grant Date	Expiry Date	Balance Outstanding Dec. 31, 2016	Changes in the Year Granted	Exercised	Expired	Balance Outstanding Dec. 31, 2017	Balance Exercisable Dec. 31, 2017
$0.70	8-Feb-12	8-Feb-17	1,400,000	-	-	(1,400,000)	-	-
$0.24	29-Jan-15	29-Jan-20	1,075,000	-	-	-	1,075,000	1,075,000
$0.39	1-Mar-15	1-Mar-20	100,000	-	-	-	100,000	100,000
$0.08	11-Feb-16	11-Feb-21	1,685,000	-	-	-	1,685,000	1,685,000
$0.08	12-Feb-16	12-Feb-21	125,000	-	-	-	125,000	125,000
$0.25	21-Sep-17	21-Sep-22	-	5,034,000	-	-	5,034,000	1,678,000
$0.28	2-Oct-17	2-Oct-22	-	150,000	-	-	150,000	50,000
			4,385,000	5,184,000	-	(1,400,000)	8,169,000	4,713,000
Weighted-average exercise price			$0.32	$0.25	-	$0.70	$0.21	$0.19

For the year ended December 31, 2018, the Company recognized $364,848 (December 31, 2017 - $332,669) in share-based payments of which $263,235 (December 31, 2017 - $233,508) was expensed as stock-based compensation and $101,613 (December 31, 2017 - $99,161) was capitalized to property, plant and equipment. These share-based payments were from the granting of 250,000 incentive stock options during 2018 (December 31, 2017 – 5,184,000) to directors, officers, employees and consultants of the Company at an exercise price of $0.25 each, of which 83,333 vested immediately.

The fair value of the granted stock options was determined using the Black-Scholes option pricing model with the following weighted-average assumptions:

	Year Ended December 31 **2018**	2017
Expected life (years)	**5.00**	5.00
Interest rate	**1.86%**	1.81%
Volatility	**66.18%**	66.18%
Fair value at grant date	**$ 0.25**	$ 0.14

The weighted-average exercise price for stock options granted during the year ended December 31, 2018 was $0.25 (year ended December 31, 2017 - $0.14). The forfeiture rate has been estimated at 5% (December 31, 2017 - 5%).

For the year ended December 31, 2018, the Company removed $nil (year ended December 31, 2017 - $875,000) from contributed surplus and recorded a corresponding recovery in deficit for expired stock options.

(c) Share purchase warrants

On September 15, 2017, the Company issued 13,750,000 warrants to a third-party lender in conjunction with its Term Loan (Note 12). 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 Company ascribed a value to the warrants of $1,428,954 by comparing the fair value of the Term Loan both with and without the warrant feature determining the difference in value to be related to the warrants. The effective rates have been disclosed in Note 12. Further, a deferred tax liability of $385,818 was incurred with regard to the warrants resulting in a net carrying amount of $1,043,136.

As at December 31, 2018, the Company had 13,750,000 outstanding and exercisable share purchase warrants.

(d) Loss per share

	Years Ended December 31	
	2018	2017
Net loss for the year	**$ (4,853,569)**	$ (3,796,176)
Weighted-average number of common shares outstanding, basic	**89,793,302**	88,495,660
Dilutive stock options and warrants	**-**	-
Weighted-average number of common shares outstanding, diluted	**89,793,302**	88,495,660
Loss per share, basic and diluted	**$ (0.05)**	$ (0.04)

For the years ended December 31, 2018 and 2017, the Company incurred a loss; therefore, dilutive stock options and warrants were nil.

14. Related Party Transactions

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

	Years Ended December 31	
	2018	2017
Salaries and wages	**$ 940,000**	$ 768,333
Share-based payments	**137,499**	172,575

15. Commitment

		2019	2020	2021	2022	2023	Total
Office Rental	$	142,864	142,864	142,864	142,864	59,527	630,983
Term Loan		-	-	-	35,458,800	-	35,458,800
Term Loan Interest		3,127,466	3,127,466	3,127,466	2,345,600	-	11,727,998
	$	3,270,330	3,270,330	3,270,330	37,947,264	59,527	47,817,781

The Company has a commitment to make monthly rental payments pursuant to the office rental agreement until May 30, 2023.

16. Supplemental Cash Flow Information

		Year Ended December 31		
		2018		2017
Provided by (used in):				
Accounts receivable	**$**	**1,081,039**	$	(460,005)
Prepaid expenses		**23,485**		(44,431)
Accounts payable and accrued liabilities		**(399,132)**		987,655
Total changes in non-cash working capital	**$**	**705,392**	$	483,219
Provided by (used in):				
Operating activities	**$**	**217,224**	$	(560,801)
Investing activities		**488,168**		1,044,020
Total changes in non-cash working capital	**$**	**705,392**	$	483,219

Cash interest paid on the Company's debts during the year ended December 31, 2018 was $2,664,211 compared to $834,078 for the year ended December 31, 2017.

17. Income Taxes

The reconciliation of income tax computed at the current statutory tax rate of 27.00% (year ended December 31, 2017 – 26.55 to income tax expense is:

		Year Ended December 31		
		2018		2017
Loss before tax	**$**	**(4,853,569)**	$	(4,343,921)
Statutory income tax rate		**27%**		26.55%
Expected income tax expense (recovery)		**(1,310,464)**		(1,153,739)
Non-deductible items		**79,205**		63,166
Other		**2,679**		(20,328)
Effect of change in tax rate		**24**		(84,797)
Amounts renounced on flow-through		**-**		144,116
Change in deferred tax asset		1,228,556		503,836
Deferred tax recovery	**$**	**-**	$	(547,746)

The combined deferred tax rate has increased from 26.55% to 27% as a result of the increase in the British Columbia tax rate from 11% to 12% effective January 1, 2018.

The tax affected items that give rise to significant portions of the deferred tax asset at December 31, 2018 and 2017 are presented below:

	December 31, 2018	December 31, 2017
Deferred tax assets		
Non-capital losses	$ **4,460,192**	$ 3,218,319
Share issue costs	-	49,651
Decommissioning obligations	**2,094,354**	1,667,551
Financial instruments	-	654,286
Term loan	**12,774**	-
	6,567,320	5,589,807
Deferred income tax liability		
Property and equipment	**(6,336,206)**	(4,975,292)
Financial instruments	**(231,114)**	-
Term loan	-	(614,515)
	$ -	$ -

The Company assessed the probability that future taxable profit will be available against which the Company can utilize the benefits of tax pools in excess of the carrying amount of assets and has not recognized a deferred tax asset in respect of the following deductible temporary differences.

	December 31, 2018	December 31, 2017
Net-capital loss carryforwards	**95,333**	95,333
Non-capital losses	**19,795,031**	15,319,328
Share issue cost	**101,171**	143,182
Debt issue cost	**1,098,959**	982,446
	$ **21,090,494**	$ 16,540,289

As at December 31, 2018, the Company has non-capital losses of approximately $36,314,261 that may be applied to reduce future Canadian taxable income, expiring as follows:

Available to	
2026	$ 546,873
2027	340,994
2028	215,784
2029	311,713
2030	323,389
2031	556,859
2032	1,736,206
2033	2,540,111
2035	7,173,180
2036	7,644,779
2037	6,040,309
2038	8,884,064
	$ 36,314,261

18. Subsequent Events

Subsequent to the year end, the Company entered into the following commodity price contracts:

Product	Type	Volume	Price	Index	Term
Crude oil	Collar	200 bbl/d	US$56.00-US$59.00	WTI-NYMEX	April 1, 2019 – June 30, 2019
Crude oil	Swap	100 bbl/d	US$12.60	WCS	April 1, 2019 – June 30, 2019
Crude oil	Swap	350 bbl/d	US$10.50	WCS	May 1, 2019 – June 30, 2019
Crude oil	Swap	250 bbl/d	US$13.50	WCS	April 1, 2019 – September 30, 2019
Crude oil	Swap	200 bbl/d	US$13.65	WCS	April 1, 2019 – September 30, 2019
Crude oil	Swap	100 bbl/d	US$17.30	WCS	July 1, 2019 – September 30, 2019
Crude oil	Swap	100 bbl/d	US$15.45	WCS	July 1, 2019 – September 30, 2019
Crude oil	Collar	100 bbl/d	US$55.00-US$63.25	WTI-NYMEX	July 1, 2019 – September 30, 2019
Crude oil	Collar	100 bbl/d	US$55.00-US$66.00	WTI-NYMEX	April 1, 2019 – December 31, 2019

OFFICERS

Don Simmons, P.Geol.
President & Chief Executive Officer

Dorlyn Evancic, CPA, CGA
Chief Financial Officer

Ian Duncan, P.Eng.
Chief Operating Officer

Andrew Arthur, P.Geol.
Vice President, Exploration

Ashley Ramsden-Wood, P.Eng.
Vice President, Engineering

BOARD OF DIRECTORS

Charles O'Sullivan, B.Sc., *Chairman*(2)(3)

Frank Borowicz, QC, CA (Hon)(1)(2)(3)

Bruce McIntyre, P.Geol.(1)(2)(4)

Don Simmons, P.Geol.(3)(4)

Gregg Vernon, P.Eng.(1)(4)

Richard Wyman, B.Sc., MBA(1)(4)

(1) Audit Committee
(2) Compensation/Nominating Committee
(3) Corporate Governance Committee
(4) Reserves Committee

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP
Calgary, Alberta
Harper Grey LLP
Vancouver, British Columbia

AUDITOR

KPMG LLP
Calgary, Alberta

TRANSFER AGENT

Computershare Investor Services Inc.
Vancouver, British Columbia

INDEPENDENT ENGINEER

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

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