Dated as at April 26, 2016

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, 2015 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, 2015 and 2014. 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, additional IFRS measures and forward-looking statements. Readers are cautioned that this document should be read in conjunction with Hemisphere's disclosure under "Non-IFRS and Additional IFRS Measures" and "Forward-Looking Statements" included at the end of this MD&A. All figures are in Canadian dollars unless otherwise noted. Tables may not add due to rounding. Certain prior period amounts may have been reclassified to conform to the current period's presentation.

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 an average working interest of 92% in 26,066 net acres and has continued to build a land position in the Jenner area through Crown landsales 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 kilometres east of the Company's Jenner property in southeastern Alberta. Hemisphere has a 100% working interest in 7,200 net acres and has been building a land position in Atlee Buffalo through Crown landsales and strategic acquisitions since 2013.

During the year, the Company strategically acquired 2.5 sections of land in a Crown landsale for approximately $64,000. These acquired lands include key surrounding areas of the Company's Atlee Buffalo Upper Mannville F and G pools and has brought the Company's land ownership to 100% over both pools. The Company also completed a strategic tuck-in acquisition of the remaining 15% working interest in 1.75 sections (1,120 acres) of land in Atlee Buffalo for a purchase price of $250,000. The Company now has 100% working interest in this land.

Operating Results

The Company generated funds flow from operations of $3,188,486 ($0.04/share) for the year ended December 31, 2015, as compared to $6,863,919 ($0.10/share) for the year ended December 31, 2014. For the fourth quarter of 2015, the Company generated negative funds flow from operations of $103,531 ($0.00/share) as compared to positive funds flow from operations of $1,433,394 ($0.02/share) for the fourth quarter of 2014.

The Company realized decreases in funds flow from operations for the three months and year ended December 31, 2015 over the comparable periods in 2014 as a result of the decline in commodity prices.

The Company reported a net loss of $8,310,831 ($0.11/share) for the year ended December 31, 2015 that included a deferred tax expense of $1,641,916 as compared to a net loss of $1,667,807 ($0.02/share) for the year ended December 31, 2014 that included a deferred tax recovery of $239,688. For the fourth quarter of 2015, the Company reported a net loss of $2,333,468 ($0.03/share) compared to a net loss of $3,568,603 ($0.05/share) for the fourth quarter of 2014.

Production

	Three Months Ended December 31		Year Ended December 31	
By product	**2015**	2014	**2015**	2014
Oil (bbl/d)	**440**	763	**607**	583
Natural gas (Mcf/d)	**879**	720	**1,003**	593
NGL (bbl/d)	**2**	3	**2**	2
Total (boe/d)	**588**	885	**776**	683
Oil and NGL weighting	**75%**	86%	**78%**	86%

In the fourth quarter of 2015, the Company's average daily production was 588 boe/d (75% oil and NGL). This decrease in production from the comparable quarter of 2014 is the result of converting two producing wells in Atlee Buffalo to injectors during the third quarter of 2015 and production downtime while workovers were performed on four producing wells during the quarter. The Company's average daily production for the year ended December 31, 2015 increased by 14% over 2014 to 776 boe/d (78% oil and NGL). This increase is the result of realizing a full year of production from the successful development of the Company's Atlee Buffalo and Jenner properties in 2014 and the optimization of production from existing wells during 2015.

During the third quarter of 2015, the Company converted two producing wells in the Upper Mannville F pool in Atlee Buffalo to injectors as part of the Company's waterflood pilot project. Based on production rates from the third quarter of 2015, the conversion of these wells reduced the Company's production by approximately 35 boe/d for the current quarter. Although the conversions have impacted the Company's production in the short-term, the conversions were essential to increasing the future oil recovery from this pool and adding to the Company's reserves.

Workovers were also performed on four wells in the fourth quarter of 2015 which resulted in a combined production shortfall of approximately 12 boe/d for the quarter. Lastly, the Company experienced some production downtime in Trutch as two gas wells were shut-in for two months of the quarter due to a facility turnaround, resulting in lost production of approximately 6 boe/d.

Average Benchmark and Realized Prices

	Three Months Ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Benchmark Prices				
WTI (US$/bbl)[(1)]	**$ 42.18**	$ 73.15	**$ 48.80**	$ 93.00
Exchange rate (1 US$/C$)	**1.3347**	1.1361	**1.2764**	1.1045
WTI (C$/bbl)	**56.30**	83.10	**62.29**	102.71
WCS (C$/bbl)[(2)]	**36.86**	66.77	**44.83**	81.11
AECO natural gas ($/Mcf)[(3)]	**2.43**	3.57	**2.65**	4.41
Average realized prices				
Crude oil ($/bbl)	**31.99**	61.66	**39.61**	73.87
Natural gas ($/Mcf)	**2.41**	3.52	**2.61**	4.08
NGL ($/bbl)	**20.81**	39.72	**21.28**	54.85
Combined ($/boe)	**$ 27.59**	$ 56.10	**$ 34.41**	$ 66.68

Notes:

(1) Represents posting prices of West Texas Intermediate Oil.

(2) Represents posting prices of Western Canadian Select.

(3) Represents the Alberta 30 day spot AECO posting prices.

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

The Company's average realized oil price for the three months and year ended December 31, 2015 decreased by 48% and 46%, respectively, from the comparable periods in 2014 which correlates to the combined impact of a lower WTI. WTI began falling in late 2014 and has remained low throughout 2015 and into 2016 as a result of a supply-demand imbalance of oil in the global market. The exchange rate remained favourable in the fourth quarter of 2015 and is expected to remain favourable through the first quarter of 2016 due to the low Canadian dollar.

The Company's average realized natural gas price decreased for the three months and year ended December 31, 2015 by 32% and 36%, respectively, from the comparable periods in 2014. These decreases correlate to AECO benchmark pricing for the three months and year ended December 31, 2015 which showed a decline of 32% and 40%, respectively, over the comparable periods of 2014.

The Company's combined average realized price decreased by 51% to $27.59/boe during the fourth quarter of 2015 from $56.10/boe during the fourth quarter of 2014. For the year ended December 31, 2015, the Company's combined average realized price decreased by 48% to $34.41/boe. These decreases are primarily the result of the decline in WTI which has extended throughout 2015.

The Company does not currently have any production hedged.

Revenue

	Three Months Ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Oil	**$ 1,295,544**	$ 4,326,223	**$ 8,776,389**	$ 15,717,054
Natural gas	**194,635**	232,914	**956,661**	883,776
NGL	**3,134**	9,149	**16,327**	34,449
Total	**$ 1,493,313**	$ 4,568,286	**$ 9,749,377**	$ 16,635,279

Revenue for the three months and year ended December 31, 2015 decreased by 67% and 41%, respectively, from the comparable periods in 2014. These decreases in revenue can be attributed to the reductions in the Company's combined average realized price for the quarter and year ended December 31, 2015 as well as the Company's lower production rate in the fourth quarter of 2015. The Company's combined average realized price for the three months and year ended December 31, 2015 decreased by 51% to $27.59/boe and 48% to $34.41/boe, respectively.

Operating Netback

	Three Months Ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Operating netback				
Revenue	**$ 1,493,313**	$ 4,568,286	**$ 9,749,377**	$ 16,635,279
Royalties	**162,564**	783,898	**774,798**	3,008,377
Operating costs	**730,570**	948,519	**2,849,900**	3,516,956
Transportation costs	**141,939**	301,535	**789,583**	834,292
Operating netback	**$ 458,240**	$ 2,534,334	**$ 5,335,096**	$ 9,275,653
Operating netback ($/boe)				
Revenue	**$ 27.59**	$ 56.10	**$ 34.41**	$ 66.68
Royalties	**3.00**	9.60	**2.73**	12.05
Operating costs	**13.50**	11.65	**10.06**	14.10
Transportation costs	**2.62**	3.70	**2.79**	3.34
Operating netback ($/boe)	**$ 8.47**	$ 31.15	**$ 18.83**	$ 37.19

Royalties for the fourth quarter of 2015 were $3.00/boe, representing a 69% decrease from the fourth quarter of 2014. For the year ended December 31, 2015, royalties decreased by 77% from the comparable period in 2014. These significant reductions are partially the result of 12 new horizontal wells drilled in 2014 which have lower associated royalty rates on initial production with an 18 month Crown royalty holiday. As at December 31, 2015, six of these 12 wells are still subject to the royalty holiday. Crown royalties have also decreased as a result of two retroactive Crown royalty rebates received in the first half of 2015, as well as lower individual well production in combination with a low Crown royalty par price. As Crown royalty par price is set based on commodity prices, the Company expects to see low Crown royalties in the first half of 2016 given the current commodity pricing environment.

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 increased for the three months ended December 31, 2015 by $1.85/boe which is a direct result of five workovers performed in the quarter representing $1.43/ boe of operating costs during the fourth quarter of 2015. Operating costs decreased for the year ended December 31, 2015 by $4.04/boe from the comparable period in 2014. This decrease is the result of higher production levels in Atlee Buffalo which have lower operating costs per boe, as well as realized economies of scale as a result of production from new wells drilled in 2014. The Company has also shut-in a number of wells with high operating costs and implemented cost control measures in order to maximize operating netback and cash flow for the period. The Company has worked with its field operators to lower labour and material costs, and has optimized field operations by internally conducting routine field repairs and activities rather than contracting externally.

Transportation costs include all costs incurred to transport emulsion and oil and gas sales to processing and distribution facilities. Transportation costs decreased for the three months and year ended December 31, 2015 by $1.08/boe and $0.56/boe, respectively, from the comparable periods in 2014. These decreases are the result of the Company's voluntary shut-in of four high water-cut wells that require trucking to facilities for processing. Transportation costs for the three months ended December 31, 2015 also decreased by 5% from the third quarter of 2015 to $2.62/boe.

Operating netback for the three months and year ended December 31, 2015 was $8.47/boe and $18.83/boe, respectively. The Company experienced decreases in operating netback in 2015 as a result of the significant decline in commodity prices, despite reductions in royalties and the Company's diligent efforts in cutting operating costs. In this challenging commodity pricing environment, the Company continues to focus on reducing field operating expenses through operational efficiencies, cutting costs, and optimizing economic wells in order to preserve operating netback and funds flow from operations.

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, 2015 decreased by $17,599 and $91,915, respectively, from the comparable periods of 2014. Exploration and evaluation expense for the three months and year ended December 31, 2015 were the result of several land expiries which occurred in 2015.

Depletion and Depreciation

	Three Months Ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Depletion expense	**$ 794,440**	$ 2,412,265	**$ 5,107,250**	$ 5,353,585
Depreciation expense	**3,364**	2,401	**13,455**	7,404
Total	**$ 797,804**	$ 2,414,666	**$ 5,120,705**	$ 5,360,989
$ per boe	**$ 14.74**	$ 29.65	**$ 18.07**	$ 21.49

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 expense for the fourth quarter of 2015 decreased by $1,616,862 over the fourth quarter of 2014. For the year ended December 31, 2015, depletion and depreciation expense decreased by $240,284 over the comparable period in 2014. These decreases are mainly the result of the Company's remaining recoverable Proved and Probable reserves determined at December 31, 2015, which increased by 11% over the comparable period in 2014. This change lowered the Company's overall depletion rate by 9% as compared to the depletion rate used at December 31, 2014.

The depletion rate is applied to the Company's depletable asset carrying value which, for the twelve months ended December 31, 2015, decreased by 13% over the comparable period in 2014. The Company's depletable asset carrying value consists of the capital expenditures spent in the area along with any FDC required to develop and produce undeveloped and non-producing reserves. The decrease is in line with the Company's reduced capital expenditures of 86% in 2015 and the reduction in the Company's FDC by 21% as compared to 2014.

Capital Expenditures

	Three Months Ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Land and lease	**$ 13,264**	$ 46,356	**$ 111,412**	$ 311,092
Geological and geophysical	**88,382**	1,080,890	**321,604**	1,747,813
Drilling and completions	**119,481**	3,923,713	**1,197,071**	13,254,809
Investment in facilities	**518,015**	1,880,248	**1,185,061**	5,370,943
Exploration and Development capital	**739,141**	6,931,208	**2,815,147**	20,684,657
Property acquisitions	**-**	-	**271,000**	634,739
Fixed assets	**-**	-	**-**	46,970
Disposition proceeds	**-**	-	**-**	(50,000)
Total capital expenditures[1]	**$ 739,141**	$ 6,931,208	**$ 3,086,147**	$ 21,316,366

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

The majority of the Company's development capital in the fourth quarter of 2015 was spent on the construction of a new pipeline at the Jenner facility to an existing disposal well. The construction of this pipeline has increased the water injection rate by 700 m3 per day which will increase the Company's production levels in the short-term while also contributing to long-term reserve additions. This project was completed on time and under budget.

The development capital costs for the year ended December 31, 2015 also included the conversion of five wells into three injectors and two water source wells and the construction of a water source pipeline as part of the Atlee Buffalo Upper Mannville F and G pool waterflood pilots. The implementation of these projects was completed on budget at approximately $1.1 million and on schedule with injection having commenced earlier than anticipated. During the year, the Company strategically acquired 2.5 sections of key land in Atlee Buffalo through a Crown landsale. The Company also completed a strategic tuck-in acquisition of the remaining 15% working interest in 1.75 sections (1,120 acres) of land in Atlee Buffalo for proceeds of $250,000. This acquired land brings the Company's land ownership to 100% over both of the Atlee Buffalo Upper Mannville F and G pools.

Hemisphere has taken a conservative approach to capital spending and investment in 2015 as a result of the current commodity pricing environment. The Company will continue to limit expenditures to essential projects and carefully selected land acquisitions until oil prices improve.

General and Administrative Expense ("G&A")

	Three Months Ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Gross G&A	**$ 535,134**	$ 1,174,466	**$ 2,063,267**	$ 2,674,693
Capitalized G&A	**(90,234)**	(128,901)	**(363,753)**	(472,530)
Total	**$ 444,900**	$ 1,045,565	**$ 1,699,514**	$ 2,202,163
$ per boe	**$ 8.22**	$ 12.84	**$ 6.00**	$ 8.83

Gross G&A for the fourth quarter of 2015 decreased by 54% from the comparable quarter in 2014 due to the Company's elimination of annual bonuses, decreased use of professional and consulting services, reduced investor relations and marketing activities, and decreased travel expenditures. Gross G&A for the twelve months ended December 31, 2015 decreased by 23% from the comparable period of 2014.

The Company capitalizes certain G&A which can be attributed to costs incurred during the period relating to its development and exploration activities. For the three months and year ended December 31, 2015, capitalized G&A decreased by 30% and 23%, respectively, from the comparable periods in 2014. These decreases in capitalized G&A are in line with lower compensation, consulting fees and overhead costs that would have been attributable to the Company's capital activities for the three months and year ended December 31, 2015.

For the three months and year ended December 31, 2015, the Company realized decreases in total G&A by $4.62/boe and $2.83/boe, respectively, from the comparable periods in 2014.

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, 2015 and 2014, the Company recorded share-based payments of $181,580 and $452,780, respectively, which represents a decrease of $271,200. This decrease is the result of a lower number of stock options issued in 2015 as compared to the previous year and the Company capitalizing $41,097 in share-based payments in the third quarter of 2015, which were directly related to the Company's development and exploration activities in the year.

The Company granted 25,000 incentive stock options in the first quarter of 2015 to an individual performing investor-related services which will vest quarterly over a twelve-month period. In the fourth quarter of 2015, 6,250 stock options vested resulting in the recognition of $375 in share-based payments.

Impairment of Property and Equipment

At each reporting date, the Company assesses its petroleum and natural gas properties and exploration and evaluation assets for possible impairment, to determine if there is any indication that the carrying amounts of the assets may not be recoverable. Impairment is recorded when the recoverable amount of an asset is less than the respective carrying amount. The recoverable amounts of the cash-generating units ("CGU") were determined with fair value less costs to sell based on expected future cash flows from Proved plus Probable reserve value, using discount rates specific to the underlying composition of assets residing in each CGU.

The prolonged reduction in crude oil and natural gas prices and deferred capital development plans were recognized by the Company as indicators of impairment at year-end. Lower commodity prices and the deferred development of properties have the effect of lowering the estimated future cash flows of CGUs and the carrying value of CGUs.

The recoverable amounts of the Company's CGUs were estimated based on the higher of the value in use and the fair value less costs to sell. The recoverable amount for the year ended December 31, 2015 was determined using value in use, based on the net present value of the before tax cash flows from oil and natural gas proved plus probable reserves estimated by the Company's external reserve evaluators discounted at a pre-tax rate of 10% to 15% per annum (2014 – 10%).

A decrease in the West Texas Intermediate ("WTI") and Western Canadian Select ("WCS") future oil price estimates combined with a decrease in the future AECO natural gas price as compared to those used in the December 31, 2014 estimates has resulted in impairment charge of $4,366,257 on the Company's developed and producing assets for the year ended December 31, 2015 as compared to $2,702,925 for the year ended December 31, 2014. Impairment charges related to Jenner and Non-core CGUs for $4,336,170 and $30,087 respectively, due to the carrying value exceeding its recoverable amount. After impairment the recoverable amount of the Jenner CGU was $16,802,308, and the Non-core CGUs were $nil.

Finance Expense

	Three Months Ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Finance expense				
Interest expense	**$ 116,870**	$ 54,794	**$ 447,096**	$ 197,682
Part XII.6 tax	**-**	581	**-**	11,889
Accretion of provision	**31,066**	40,516	**124,263**	66,776
Total finance expense	**$ 147,936**	$ 95,891	**$ 571,358**	$ 276,347
$ per boe	**$ 2.73**	$ 1.18	**$ 2.02**	$ 1.11

Finance expense for the three months and year ended December 31, 2015 increased by $52,045 and $295,012, respectively, over the comparable periods in 2014. These increases are the result of the interest expense incurred on the utilization of the Company's credit facility which carried a higher balance in 2015 as compared to 2014 as well as the accretion expense incurred for the period.

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. For the three months and year ended December 31, 2015, accretion expense was $31,066 and $124,263, respectively. The increases in accretion expense in 2015 over the comparable periods of 2014 are a result of the decommissioning obligations associated with the 12 new wells drilled and 14 wells acquired during the 2014 year.

Tax Pools and Deferred Taxes

The Company has approximately $47 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 2015. Taxes payable beyond 2015 will primarily be a function of commodity prices, capital expenditures and production volumes.

	Deduction Rate	**December 31, 2015**	December 31, 2014
Canadian exploration expense (CEE)	100%	**$ 3,336,823**	$ 3,336,823
Canadian development expense (CDE)	30%	**19,220,505**	24,371,718
Canadian oil and gas property expense (COGPE)	10%	**7,517,421**	8,352,690
Non-capital losses carry forwards (NCL)	100%	**13,734,893**	6,571,929
Undepreciated capital cost (UCC)	20-55%	**2,171,731**	2,870,328
Share issuance costs and other	Various	**797,356**	1,591,613
Total		**$ 46,778,729**	$ 47,095,101

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, 2015		Year Ended December 31, 2014		Year Ended December 31, 2013
Average daily production (boe/d)		**776**		683		463
Petroleum and natural gas revenue	**$**	**9,749,377**	$	16,635,279	$	10,573,199
Petroleum and natural gas netback		**5,335,096**		9,275,653		5,607,492
Funds flow from operations(1)		**3,188,486**		6,863,919		3,789,202
Per share, basic and diluted		**0.04**		0.10		0.07
Net loss(2)		**(8,310,831)**		(1,667,807)		(510,266)
Per share, basic and diluted		**(0.11)**		(0.02)		(0.01)
Average realized price ($/boe)		**34.41**		66.68		62.55
Operating netback ($/boe)(3)		**18.83**		37.19		33.17
Capital expenditures, including property acquisitions		**3,086,147**		21,316,366		9,969,174
Net debt(4)		**11,446,110**		11,644,609		6,330,906
Bank indebtedness		**10,828,040**		7,184,147		4,500,000
Total assets(2)		**40,811,044**		48,951,632		32,195,577

Notes:

(1) Funds flow from operations is an additional IFRS measure that represents cash generated by operating activities, before changes in non-cash working capital and decommissioning expenditures and may not be comparable to measures used by other companies.

(2) Certain annual amounts were restated retrospectively for December 31, 2013 due to a change in accounting policy as disclosed in Note 4 of the Company's audited annual financial statements for the year ended December 31, 2014.

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

(4) Net debt is a non-IFRS measure calculated as current assets minus current liabilities including bank indebtedness and excluding flow-through share premium.

Summary of Quarterly Results

	2015				2014			
	Dec. 31 Q4(2)	Sep. 30 Q3(3)	Jun. 30 Q2(4)	Mar. 31 Q1(5)	Dec. 31 Q4(6)	Sep. 30 Q3(7)	Jun. 30 Q2(8)	Mar. 31 Q1(9)
Average daily production (boe/d)	**588**	678	849	995	885	725	553	567
Petroleum and natural gas revenue	**1,493,313**	2,043,781	3,284,020	2,928,264	4,568,286	4,703,496	3,799,461	3,564,036
Petroleum and natural gas netback	**458,240**	1,094,625	1,954,246	1,827,986	2,534,334	2,852,204	2,011,113	1,878,003
Funds flow from operations	**(103,531)**	714,505	1,320,981	1,256,531	1,433,394	2,330,091	1,563,174	1,537,260
Per share, basic and diluted	**(0.00)**	0.01	0.02	0.02	0.02	0.03	0.02	0.02
Net income (loss)(1)	**(2,333,468)**	(4,755,531)	(575,484)	(646,345)	(3,568,603)	720,312	554,465	626,019
Basic and diluted income (loss) per share	**(0.03)**	(0.06)	(0.01)	(0.01)	(0.05)	0.01	0.01	0.01
Combined average realized price ($/boe)	**27.59**	32.74	42.49	32.71	56.10	70.52	75.47	69.89
Operating netback ($/boe)	**8.47**	17.54	25.28	20.42	31.14	42.79	39.98	36.83

Notes:

(1) Certain quarterly amounts were restated retrospectively as disclosed in Note 4 of the Company's audited annual financial statements for the year ended December 31, 2014.

(2) Funds flow from operations and petroleum and natural gas netback decreased in this quarter as a result of a 51% reduction in the Company's combined average realized price from the fourth quarter of 2014. The Company also experienced a decrease in production for the quarter as a result of the conversion of two producing wells to injectors as part of the Company's waterflood pilot project. A significant portion of the net loss in this quarter is the result of an impairment charge of $1,353,696 on the Company's developed and producing assets.

(3) Funds flow from operations and petroleum and natural gas netback decreased in this quarter as a result of a 54% reduction in the Company's combined average realized price. The Company does not anticipate its deferred tax asset will be realized in the near future; as a result it has provided for it in the amount of $1,236,816 in the third quarter of 2015. A significant portion of the net loss in this quarter is the result of an impairment charge of $3,012,561 against the Company's petroleum and natural gas properties.

(4) Funds flow from operations and petroleum and natural gas netbacks have shown a slight improvement over the first quarter of 2015 due to a 30% increase in the Company's combined average realized price, but have remained low compared to 2014 as a result of the decline in commodity prices. Due to taxable income generated in excess of tax pools from lower capital expenditures, the Company utilized deferred tax assets resulting in a deferred tax expense of $405,100 for the second quarter of 2015.

(5) The decreases in net income, funds flow from operations and petroleum and natural gas netbacks can be attributed to the decrease in the Company's combined average realized price resulting from the decline in oil prices.

(6) A significant portion of the loss is due to the $2,702,925 recorded in property impairment and an increase in depletion expense as a result of a change in the Company's depletion accounting policy.

(7) Net income can be attributed to a combination of the increase in the Company's production from its summer drilling program and the improvement of netback resulting from decreased operating and transportation costs.

(8) The improvement in net income over certain prior quarters is primarily due to the Company's increase in the combined average realized price resulting in higher operating netback.

(9) The improvement in net income is primarily due to the Company's increased production levels from the drilling of three new wells and an increase in combined average realized price.

Outstanding Share Data

	April 26, 2016	**December 31, 2015**	December 31, 2014
Fully diluted share capital			
Common shares issued and outstanding	75,903,498	**75,803,498**	75,368,498
Stock options	5,010,000	**5,995,000**	5,970,000
Total fully diluted	80,913,498	**81,798,498**	81,338,498

Subsequent to December 31, 2015, the following events impacted the Company's share capital:

- On January 27, 2016, 200,000 incentive stock options expired at a price of $0.30.
- On February 9, 2016, 50,000 incentive stock options expired at a price of $0.38.
- On February 11, 2016, the Company granted incentive stock options to officers, directors, employees and consultants of the Company entitling them to purchase up to a total of 1,785,000 common shares at an exercise price of $0.08 each.
- On February 12, 2016, the Company cancelled a total of 2,395,000 incentive stock options granted to certain officers, directors, employees and consultants who voluntarily returned these options to the Company. The cancelled options were granted from April 2012 to October 2014 and were exercisable at prices ranging from $0.50 to $0.65 for a period of five years from the date of grant.
- On February 12, 2016, the Company granted incentive stock options to an employee and consultants of the Company entitling them to purchase up to a total of 200,000 common shares at an exercise price of $0.08 each.
- On April 7, 2016, 100,000 incentive stock options were exercised at a price of $0.08 per share for gross proceeds of $8,000.
- On April 15, 2016, 225,000 incentive stock options were cancelled at exercise prices ranging from $0.24 to $0.70.

The Company has the following stock options that are outstanding and exercisable as at April 26, 2016:

Exercise Price	Expiry Date	Balance Outstanding April 26, 2016	Balance Exercisable April 26, 2016
$0.40	26-May-16	475,000	475,000
$0.70	8-Feb-17	1,400,000	1,400,000
$0.24	29-Jan-20	1,150,000	1,150,000
$0.39	1-Mar-20	100,000	100,000
$0.08	11-Feb-21	1,685,000	1,610,000
$0.08	12-Feb-21	200,000	200,000
		5,010,000	4,935,000
Weighted-average exercise price		$0.33	$0.33

Liquidity and Capital Management

The Company's net debt as at December 31, 2015 and 2014 was $11,446,110 and $11,644,609, respectively, representing a decrease in net debt of $198,501.

a) Financing

The Company's cash provided by financing activities for the year ended December 31, 2015 was $3,752,644, which included an increase in bank indebtedness of $3,643,893. During the year, the Company also issued 435,000 common shares through the exercise of stock options at $0.25 each for gross proceeds of $108,751.

For the year ended December 31, 2014, the Company's cash provided by financing activities was $12,013,775, which included an increase in bank indebtedness of $2,684,147. During the 2014 year, the Company also closed a bought-deal equity financing on May 14, 2014 consisting of 13,333,500 common shares at a price of $0.75 per common share for aggregate gross proceeds of $10,000,125. For the year ended December 31, 2014, the Company issued 690,000 common shares for the exercise of incentive stock options at various prices for gross proceeds of $220,850. Additionally, the Company issued 37,500 common shares from the exercise of share purchase warrants at a price of $0.75 for gross proceeds of $28,125.

b) Capital Resources

The Company has a demand operating credit facility in the amount of $15.0 million with Alberta Treasury Branches ("ATB") which was renewed in July 2015. Funds available under the credit facility are restricted to $14.0 million and access to the remaining $1.0 million is based on additional approval from ATB.

The facility is secured by a general security agreement and a floating charge on all lands of the Company. The facility bears interest at the bank's prime rate plus 1.75%, as well as a standby charge for any undrawn funds. As the available lending limits of the facilities are based on the bank's interpretation of the Company's reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review. The Company is currently conducting its review with ATB, which it expects to have completed in the May 2016.

Pursuant to the terms of the credit facility, the Company has provided a financial covenant that at all times its working capital ratio shall not be less than 1.0. The working capital ratio is defined under the terms of the credit facilities as current assets including the undrawn portion of the revolving operating demand line credit facility ($14.0 million), to current liabilities, excluding any current bank indebtedness.

At December 31, 2015, the Company has drawn a total of $10,828,040 from the credit facility (December 31, 2014 - $7,184,147) and had a working capital ratio of 3.0, which is in compliance with the above financial covenant.

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.

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 net debt. The Company may manage its capital structure by issuing new shares, repurchasing outstanding shares, obtaining additional financing from the Company's credit facilities, 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

During the three months and year ended December 31, 2015, the Company paid fees of $10,000 and $40,000, respectively, to a director of the Company. These fees were charged for services provided by the Chairman of the Company's Board of Directors.

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

	Three Months Ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Short-term benefits	**$ 205,000**	$ 502,500	**$ 820,000**	$ 986,666
Share-based payments	-	49,723	**135,660**	377,743

Short-term benefits, which are primarily salaries and wages, have decreased during the three months and year ended December 31, 2015 as a result of the elimination of annual bonuses in the year.

Commitment

The Company has a commitment to make monthly rental payments pursuant to the office rental agreement at its current location until May 30, 2018. The following table shows the Company's rental commitment amounts for the next three fiscal years:

	2016	2017	2018
Lease commitment	**$ 193,461**	$ 193,461	$ 80,609

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 and policies are set out in Notes 2 and 3 of the audited annual financial statements for the year ended December 31, 2015 and have been consistently followed in the preparation of the 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.

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.

Future Accounting Pronouncements

The IASB or IFRIC have issued pronouncements effective for accounting periods beginning on or after January 1, 2016. Only those which may significantly impact the Company are discussed below:

a) IFRS 15 *Revenue from Contracts with Customers* provides a single, principles based five-step model to be applied to all contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transaction to determine whether, how much and when revenue is recognized. New judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized. New disclosures about revenue are also introduced. The new standard is effective for annual periods beginning on or after January 1, 2018.

b) IFRS 9 *Financial Instruments (2014)* is a finalized version of IFRS 9, which contains accounting requirements for financial instruments, replacing IAS 39 *Financial Instruments: Recognition and Measurement*. The standard contains requirements in the following areas:

- Classification and measurement. Financial assets are classified by reference to the business model within which they are held and their contractual cash flow characteristics. The 2014 version of IFRS 9 introduces a "fair value through other comprehensive income" category for certain debt instruments. Financial liabilities are classified in a similar manner to under IAS 39; however, there are differences in the requirements applying to the measurement of an entity's own credit risk.
- Impairment. The 2014 version of IFRS 9 introduces an "expected credit loss" model for the measurement of the impairment of financial assets, so it is no longer necessary for a credit event to have occurred before a credit loss is recognized.
- Hedge accounting. Introduces a new hedge accounting model that is designed to be more closely aligned with how entities undertake risk management activities when hedging financial and non-financial risk exposures.

  The mandatory effective date for IFRS 9 is for annual periods beginning on or after January 1, 2018 and must be applied retrospectively with some exemptions.

c) IFRS 16 *Leases* requires the recognition of most leases on the balance and effectively removes the classification of leases as either finance or operating leases and treats all leases as finance leases for lessees with exemptions for short-term leases where the lease term is twelve months or less and for leases of low value items. IFRS 16 accounting treatment for lessors is unchanged, which provides the choice of classifying a lease as either a finance or operating lease. The new standard is effective for annual periods beginning on or before January 1, 2019.

The Company has not fully completed its evaluation of the effect of adopting these standards on its financial statements. The Company will adopt IFRS 15, IFRS 9 and IFRS 16 when required by the IASB.

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, 2015, the Company's financial instruments include accounts receivable, reclamation deposits, bank indebtedness, accounts payable and accrued liabilities.

The fair values of accounts receivable, reclamation deposits, bank indebtedness, accounts payable and accrued liabilities approximate their carrying values due to the short-term maturity of these financial instruments.

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 venture partners and oil and natural gas marketers and its reclamation deposits. Any risk associated with accounts receivable is minimized substantially by the financial strength of the Company's joint venture partners, operators and marketers. The credit risk associated with reclamation deposits is mitigated by ensuring these financial assets are placed with major financial institutions with strong investment-grade ratings by a primary ratings agency. The Company does not anticipate any default. There are no balances past due 90 days or impaired.

The maximum exposure to credit risk is as follows:

	As at	
	December 31, 2015	December 31, 2014
Accounts receivable		
Trade receivables	**$ 385,432**	$ 1,208,897
Receivables from joint venture	**153,897**	95,355
Reclamation deposits	**115,535**	105,535
Total	**$ 654,864**	$ 1,409,787

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. The Company historically 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 come due. The Company manages liquidity risk by anticipating operating, investing and financing activities and ensuring 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 expenditure budgets on a quarterly and annual basis which are regularly monitored and updated when necessary in order to review debt forecasts and working capital requirements.

At December 31, 2015, the Company had net debt of $11,446,110 (December 31, 2014 - $11,644,609), which includes bank indebtedness of $10,828,040 (December 31, 2014 - $7,184,147). The Company funds its operations through production revenue and a demand operating credit facility. All of the Company's financial liabilities have contractual maturities of less than 90 days.

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 credit facilities are subject to variable interest rates. A one percent change in interest rates would not have a material effect on net loss and comprehensive 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; however, 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 did not have any foreign exchange rate swaps or related contracts in place as at the date of this document.

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 ability to raise capital. The Company has not entered into any commodity hedge contracts as at the date of this document.

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 and Additional IFRS Measures

This document contains the terms "funds flow from operations" which is an additional IFRS measure presented in the financial statements. This document also contains the terms "operating netback" and "net debt" which are not recognized measures under IFRS and may not be comparable to similar measures presented by other companies.

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

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

	Three Months Ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Cash provided by (used in) operating activities	**$ (171,749)**	$ 1,645,958	**$ 2,993,272**	$ 6,850,566
Decommissioning obligation expenditures	**-**	-	**2,591**	-
Change in non-cash working capital	**68,218**	(212,564)	**192,622**	13,353
Funds flow from (used in) operations	**$ (103,531)**	$ 1,433,394	**$ 3,188,486**	$ 6,863,919
Per share, basic and diluted	**$ (0.00)**	$ 0.02	**$ 0.04**	$ 0.10

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

c) 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 bank debt and current liabilities, less current assets. There is no IFRS measure that is reasonably comparable to net debt.

The following table outlines the Company calculation of net debt:

	December 31, 2015	December 31, 2014
Current assets	**$ 686,869**	$ 1,437,181
Current liabilities[1]	**(1,304,939)**	(5,897,643)
Bank indebtedness	**(10,828,040)**	(7,184,147)
Net debt	**$ (11,446,110)**	$ (11,644,609)

Note:

(1) Excluding bank indebtedness and flow-through premium liability.

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. In addition, given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

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 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 may contain forward-looking statements pertaining to the following: volumes and estimated value of Hemisphere's oil and natural gas reserves; the life of Hemisphere's reserves; the volume and product mix of Hemisphere's oil and natural gas production; future oil and natural gas prices; future operational activities; and future results from operations and operating metrics, including any future production growth and net debt, management's plans to accelerate development in the event of a recovery in commodity prices, and management's plans to continue with 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) 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, 2015 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 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.