IRONHORSE OIL & GAS INC.
MANAGEMENT'S DISCUSSION & ANALYSIS

This management's discussion and analysis ("MD&A") for Ironhorse Oil and Gas Inc. ("Ironhorse" or the "Company" or "we" or "our"), dated November 28, 2017, should be read in conjunction with the condensed financial statements for the three and nine months ended September 30, 2017 and September 30, 2016 and the audited financial statements for the years ended December 31, 2016 and December 31, 2015.

The interim condensed financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which comprises International Financial Reporting Standards ("IFRS") as applicable for the interim financial statements, including International Accounting Standards ("IAS") 34, "Interim Financial Reporting".

This MD&A contains Non-GAAP measures and forward-looking statements. Readers are cautioned that the MD&A should be read in conjunction with Ironhorse's disclosure under the Advisory heading included at the end of this MD&A. Additional information relating to Ironhorse can be found on SEDAR at www.sedar.com or on the Company's website at www.ihorse.ca.

2017 OVERVIEW

Ironhorse is engaged in the development and production of petroleum and natural gas reserves in western Canada. Ironhorse's shares are listed on the TSX Venture Exchange under the symbol IOG-V.

The Company's working capital position remained flat at $3.0 million at September 30, 2017, compared with $3.1 million at June 30, 2017. The Company realized a net loss of $3.3 million for Q3 2017 a 120% increase compared to a loss of $1.5 million for Q2 2017. The Q3 2017 loss pertained to a $1.6 million impairment charge at Pembina which reflects fair market value discussions with external parties related to the proposed transaction with Pond Technologies Inc. ("Pond") and a $1.4 million non-cash deferred tax expense resulting from the reduction of the deferred tax asset recorded as the future net taxable income horizon was reduced.

Production during the third quarter of 2017 declined to104 boe/d compared to165 boe/d for Q2 2017 as the Pembina 9-5 well had unanticipated downtime and repair and maintenance work occurring during a significant portion of September. The Pembina 14-5 well continued to produce intermittently due to water cut increases that cause the well to load up and require reservoir pressure to build up in order to continue to flow against the gathering system pressure. The Pembina L2L pool is on water flood and water cuts are expected to increase significantly over the life of both wells. The installation of a down hole pump (typical operation of this type of reservoir), was completed in late October 2017 restoring production to stabilized rates during the latter part of Q4 2017.

Operating netbacks for Q3 2017 declined by 78% to $57,000 compared to $256,000 for Q2 2017 corresponding with 37% lower production, a 10.7% decrease in the Company's realized average oil price and higher operating costs attributed to repair and maintenance work and prior period costs recorded.

On August 14, 2017, Ironhorse and Pond Technologies Inc. ("Pond") entered into an arm's length non-binding letter of intent pursuant to which Ironhorse and Pond propose to complete a business combination by way of take-over bid (the "Proposed Transaction"). The Ironhorse Shares were halted until terms of the Proposed Transaction were completed. Pursuant to the Proposed Transaction, Ironhorse will offer to purchase all of the common shares of Pond ("Pond Shares") in exchange for common shares of Ironhorse ("Ironhorse Shares") issued from treasury. Holders of Pond Shares will receive 6.9 Ironhorse Shares for each 1 Pond Share held resulting in the issuance of approximately 79,289,591 Ironhorse Shares at a deemed issued price of $0.29 per Ironhorse Share for aggregate ascribed value of approximately $23 million. The Proposed Transaction will constitute a reverse-takeover and change of business of Ironhorse pursuant to the policies of the TSX Venture Exchange (the "TSXV") and is subject to the acceptance of the TSXV and the approval of the holders of Ironhorse Shares.

On October 4, 2017, Ironhorse, entered into an amalgamation agreement (the “Amalgamation Agreement”) with Pond and a wholly-owned subsidiary of Ironhorse providing for the acquisition (the “Acquisition”) by Pond of Ironhorse by way of a three-cornered amalgamation. All of the directors and officers of Pond and Ironhorse have entered into support agreements pursuant to which they have agreed to vote their outstanding common shares of Pond (“Pond Shares”) or Ironhorse (“Ironhorse Shares”), as applicable, in favor of the Acquisition and related matters. Under the terms of the Amalgamation Agreement, Pond will amalgamate with the wholly-owned subsidiary of Ironhorse (the “Amalgamation”) and, following the completion of the proposed transaction, the resulting amalgamated entity (“Amalco”) will be a wholly-owned subsidiary of Ironhorse, which is expected to continue trading on the TSX Venture Exchange (the “TSXV”).

The Amalgamation Agreement also provides for: (i) a name change of Ironhorse to “Pond Technologies Holdings Inc.” or such other name as Pond may determine in its sole discretion; (ii) the consolidation of all of the issued and outstanding Ironhorse Shares on the basis of 6.9 pre-consolidation Ironhorse Shares for each one post-consolidation Ironhorse Share; (iii) the appointment of a new management team; and (iv) the reconstitution of the board of directors of Ironhorse (collectively with the Acquisition and the Amalgamation, the “Transaction”). As a condition of the Transaction, Pond will complete a brokered private placement of subscription receipts, at a price of not less than $2.00 per subscription receipt, on a commercially reasonable efforts agency basis for minimum aggregate gross proceeds of $6,500,000 and maximum aggregate gross proceeds of $15,000,000. Net proceeds are expected to be used to fund Amalco’s program to commercialize its technology following completion of the Transaction and for general corporate purposes.

On November 16, 2017 the Amalgamation Agreement was amended to reflect the reduction of the maximum size of the financing from $15,000,000 to $10,000,000 and the treatment of certain unit purchase warrants of Pond held by the Agents and the Pond Agent Warrants upon the completion of the Transaction. A copy of this agreement can be found on Sedar under Ironhorse’s issuer profile at www.sedar.com.

On November17, 2017 Ironhorse and Pond completed a joint management information circular in connection with an annual and special meeting of Ironhorse shareholders to be held on December 18, 2017 (the “Ironhorse Meeting”) and a special meeting of Pond shareholders to be held on December 15, 2017 (the “Pond Meeting”) to Ironhorse shareholders of record as of November 13, 2017 and Pond shareholders of record as of November 16, 2017. At the Ironhorse Meeting, Ironhorse shareholders will be asked, among other matters, to approve Ironhorse’s previously announced business combination with Pond by way of a “three-cornered amalgamation” (the “Transaction”), a name change of Ironhorse to “Pond Technologies Holdings Inc.” or such other name as is acceptable to the applicable regulatory authorities and the consolidation of all of the issued and outstanding common shares of Ironhorse (“Ironhorse Shares”) on the basis of 6.9 pre-consolidation Ironhorse Shares for each one post-consolidation Ironhorse Share. At the Pond Meeting, Pond shareholders will be asked to approve the amalgamation (the “Amalgamation”) of Pond and 2597905 Ontario Inc. (“Newco”), a wholly-owned subsidiary of Ironhorse, under the provisions of the Business Corporations Act (Ontario) to form a new amalgamated company (“Amalco”). Upon the completion of the Transaction, Amalco will be a wholly-owned subsidiary of Ironhorse. A copy of the Circular is available under Ironhorse’s issuer profile on SEDAR at www.sedar.com.

The TSXV has conditionally accepted the Transaction, which will constitute a reverse takeover and change of business of Ironhorse pursuant to the TSXV’s policies, subject to Ironhorse fulfilling all of the requirements of the TSXV. Trading of Ironhorse Shares on the TSXV resumed on November 23, 2017.

General and administrative costs incurred during the nine month period ended September 30, 2017 have increased 26% to $430,000 compared with $341,000 for 2016, with $172,000 of 2017 expenses pertaining to costs incurred in relation to the Proposed Transaction with Pond.

OUTLOOK

Combined production from the Pembina Nisku light oil property in October averaged 762 boe/d gross (119 boe/d net), reflective of the 14-5 well’s intermittent production and downtime attributed to the pump installation during the month. The Company’s share of capital costs incurred during October 2017 for the electrical upgrade and 14-5 well pump installation are estimated at $78,000. The Pembina 9-5 well is currently operating with limited down time and the water cut remains low.

Net Pembina Q4 2017 production guidance is anticipated to be in the range of 100 to 120 boe/d due to restricted flow as a result of a piping failure at the Sinopec operated 13-2 battery. The repair is scheduled to be completed by the end of November.

Q1 2018 net Pembina production is expected to be 150 to 170 boe/d with both wells producing at full capability.

Lawsuit – Statement of Claim Filed and Counter claim

On February 23, 2016, the Company and Grizzly Resources Ltd. ("GRL"), the operator of the Pembina wells, jointly filed a Statement of Claim in the Court of Queen's Bench of Alberta against Sinopec. The Company and GRL are seeking damages against Sinopec for misrepresentation and breach of contract.
On April 15 2016 Sinopec filed a Statement of Defense, as well as a Counterclaim, in response to the Company's and GRL's Statement of Claim. On May 24, 2016 Ironhorse and GRL filed a Statement of Defense to the Sinopec Counterclaim.

SELECTED QUARTERLY INFORMATION

	For the three months ended		
($ thousands except per share amounts)	**September 30 2017**	June 30 2017	September 30 2016
Petroleum and natural gas revenues[1]	**415**	734	669
Funds from operations[2]	**(107)**	99	53
Net loss	**(3,259)**	(1,522)	(123)
Net loss per share-basic & diluted	**(0.12)**	(0.05)	-
Total assets	**8,473**	11,830	14,100
Net working capital	**2,952**	3,063	2,660

(1) Petroleum and natural gas revenues are before royalty expense.
(2) Funds from operations is a non-GAAP measure as defined in the Advisory section of the MD&A.

FINANCIAL AND OPERATING REVIEW

Production

	Three Months Ended September 30			Nine Months Ended September 30		
	2017	2016	% Change	**2017**	2016	% Change
Light oil & NGL(bbl/d)	**90**	145	(38)	**123**	64	92
Natural gas (mcf/d)	**84**	162	(48)	**127**	118	8
Total (boe/d)	**104**	172	(40)	**144**	84	71
Volumes by product						
Oil & NGL	**87%**	84%	4	**85%**	76%	12
Natural gas	**13%**	16%	(19)	**15%**	24%	(38)

For the three months and nine months ended September 30, 2017 Ironhorse's average daily light oil and natural gas liquids ("NGL") sales volumes were 90 bbls/d and 123 bbls/d, respectively. This represents a decrease of 38% and increase of 92% compared to an average sales volume of 145 bbls/d and 64 bbls/d for the same periods of 2016.

The significant rise in the year-to-date production volumes is the result of the Pembina Nisku light oil property producing for just 31 days during the first seven months of the comparative 2016 period as the property was shut-in on January 19, 2016 to preserve the value of the reserves until commodity prices recovered. Current quarter sales volumes were lower than anticipated as compared to Q3 2016 due to unexpected downtime resulting from required repair work on the Pembina 9-5 well and intermittent production from the Pembina 14-5 well as installation of the downhole pump was completed in late October 2017.

Natural gas sales volumes for the three and nine months ended September 30, 2017, were 84 mcf/d and 127 mcf/d respectively representing a decrease of 48% and increase of 8% compared to an average sales volume of 162 mcf/d and 118 mcf/d for the same periods of 2016. The three and nine month to date variances are due mainly to the Company's Pembina production levels as discussed above. 2017 gas production is comprised entirely from Pembina as the Balsam Alberta well has not produced in 2017.

Commodity Prices

	Three Months Ended September 30			Nine Months Ended September 30		
	2017	2016	% Change	**2017**	2016	% Change
Average benchmark prices:						
WTI (US$/bbl)	**48.20**	44.94	7	**49.47**	40.84	21
Canadian Light Sweet ($/bbl)	**57.15**	54.19	5	**60.57**	49.44	23
AECO natural gas ($/mcf)[1]	**1.61**	2.36	(32)	**2.36**	1.77	33
Realized prices:						
Light oil & NGL ($/bbl)	**49.05**	47.85	3	**54.29**	44.98	21
Natural gas ($/mcf)	**1.17**	2.17	(46)	**2.40**	1.94	24
Total ($/boe)	**43.39**	42.38	2	**48.45**	37.09	31

(1) Represents the AECO Monthly (7a) Index

Revenues

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2017**	2016	% Change	**2017**	2016	% Change
Light oil & NGL	**406**	637	(36)	**1,824**	784	133
Natural gas	**9**	32	(72)	**83**	63	32
Total	**415**	669	(38)	**1,907**	847	125

Revenues and Commodity Prices

The Company's realized light oil and NGL price/bbl for the three and nine months ended September 30, 2017, was 3% and 21% higher respectively compared to the same periods in 2016 and were on par with the benchmark Canadian Light Sweet ("CLS") price percentage increases. The Q3 2017 CLS benchmark oil prices averaged $57.15/bbl trending 4% lower compared to the Q2 2017 average of $59.72/bbl.

The Company's realized natural gas price/mcf for the three months and nine months ended September 30, 2017, was 46% lower and 24% higher respectively compared to the same periods in 2016. The benchmark natural gas price decreased 32% and rose 33% higher for the three months and nine months ended September 30, 2017 compared to the same periods in 2016. The Company's realized natural gas and oil prices vary from benchmark prices due to transportation and location differentials.

Total sales revenue for the three months ended September 30, 2017 was $415,000 a 38% decrease from $669,000 for the three months ended September 30, 2016. Revenues for the nine months ended September 30, 2017 rose by 125% from $847,000 to $1,907,000. This considerable increase in year-to-date sales revenue was a result of increased sales volumes for both oil and natural gas, mainly attributable to Pembina which produced for most of the current year compared to producing for just 92 days during the comparative 2016 period and higher trending commodity prices in 2017. Lower revenues for Q3 2017 correlated with 40% lower Pembina production during the quarter compared to Q3 2016.

Realized revenues on a boe basis for the three and nine month periods ended September 30, 2017 was 2% at $43.39/boe and 31% higher at $48.45/boe compared to the same periods in 2016, reflective of the impact of higher commodity prices and increased oil production weighting as compared to 2016, as Pembina was shut-in for 66% of the comparable period in 2016 and the Balsam natural gas well had reported gas production.

Royalties

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except per boe)	**2017**	2016	% Change	**2017**	2016	% Change
Oil & NGL	**174**	276	(37)	**796**	341	133
Natural gas	**(6)**	(5)	20	**(34)**	(55)	(38)
Royalties	**168**	271	(38)	**762**	286	166
Royalties %	**40**	41	(2)	**40**	34	18
Royalties per boe	**17.59**	17.16	3	**19.36**	12.55	54

Royalties represent charges against production or revenue by governments and mineral right owners. From period to period royalties vary due to changes in the production mix, production rates and sales prices, the components of which are subject to different royalty rates.

For the three months ended September 30, 2017, royalties decreased 38% from $271,000 in the comparable period in 2016 to $168,000, corresponding with the current quarter production decrease of 40% compared to 2016. Royalties as a percentage of revenues remained flat at 40% for the three months ended September 30, 2017 compared to 41% in the comparable 2016 period.

Royalties increased by 166% to $762,000 for the nine months ended September 30, 2017, compared to $286,000 for the same period in 2016, due to higher oil and gas production reported during the current year. Royalties as a percentage of revenues increased 18% to 40% for the nine months ended September 30, 2017, compared to the same period in 2016. This significant 2017 increase in royalties incurred and on a percentage basis, is primarily due to the impact of the 2016 gas royalty recoveries recorded in 2017 being significantly lower than in 2016. Natural gas royalty recoveries of $22,000 and $59,000 were recorded during nine month periods of 2017 and 2016 related to gas cost allowance and custom processing fee credits received associated with natural gas crown royalties previously paid.

Operating Expenses

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except per boe)	**2017**	2016	% Change	**2017**	2016	% Change
Operating expenses	**189**	261	(28)	**560**	406	38
Operating expenses ($/boe)	**19.79**	16.56	20	**14.22**	17.78	(20)

Operating expenses were $189,000 or $19.79/boe, for the three months ended September 30, 2017, compared to $261,000 or $16.56/boe for the comparable period in 2016 representing a decrease of 28% and increase of 20% respectively. For the nine months ended September 30, 2017, operating costs increased by 38% to $560,000 or $14.22/boe compared to $406,000 or $17.78/boe compared to the same period in 2016.

The Q3 2017 operating costs on a boe basis are higher than the comparable Q3 2016 period as a result of lower production, increased repair and maintenance costs and prior period costs recorded during the current quarter.

The rise in 2017 operating expenses incurred is due to higher Pembina production levels in 2017 compared to 2016. The 2017 reporting period includes equalization (thirteen-month operating cost fee adjustment) credits of $92,000 ($2.35/boe) recorded in the current year related to the 2015 production year. Normalized operating expenses for 2017 were $16.57/boe, exclusive of the equalization credits.

Operating Netbacks

	Three Months Ended September 30			Nine Months Ended September 30		
	2017	2016	% Change	**2017**	2016	% Change
Oil & NGL ($/bbl)	**49.05**	47.85	3	**54.29**	44.98	21
Natural gas ($/mcf)	**1.17**	2.17	(46)	**2.40**	1.94	24
Revenues ($/boe)	**43.39**	42.38	2	**48.45**	37.09	31
Royalties ($/boe)	**(17.59)**	(17.16)	3	**(19.36)**	(12.55)	54
Operating expenses ($/boe)	**(19.79)**	(16.56)	20	**(14.22)**	(17.78)	(20)
Operating netback ($/boe)	**6.01**	8.66	(31)	**14.87**	6.76	120

Ironhorse's operating netback per boe for the three months ended September 30, 2017, declined 31% from the three months ended September 30, 2016. For the nine months ended September 30, 2017, operating netback was $14.87/boe compared to $6.76/boe in the same period in 2016 representing a 120% increase. Realized oil and liquids prices increased 3% and 21% for the three and nine months ended September 30, 2017 respectively as a result of commodity price improvements.

The increased netback in 2017 compared to 2016 is the result of significantly higher oil production and lower operating costs reported at Pembina, offset by higher royalties as compared to Pembina being shut-in for 66% of the prior year.

The current quarter netback variance compared to Q3 2016 was primarily attributed to higher operating costs incurred and lower production.

General and Administrative (G&A) Expense and Stock-based Compensation

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except per boe)	**2017**	2016	% Change	**2017**	2016	% Change
G&A expense	**171**	89	92	**430**	341	26
G&A expense ($/boe)	**17.94**	5.62	219	**10.93**	14.94	(27)

G&A expense for the three months ended September 30, 2017, increased 92% to $171,000 from $89,000 for the three months ended September 30, 2016. The Q3 2017 increase was largely a result of consulting costs incurred associated with the proposed transaction announced on August 14, 2017 between Ironhorse and Pond as previously described in this MD&A. G&A expenses for the nine months ended September 30, 2017, increased 26% to $430,000 from $341,000 for the same period in 2016. Year to date G&A includes $172,000 of costs related to the Pond transaction which relates to 40% of total 2017 G&A. Q3 2016, in comparison, included $55,000 of costs related to the unsolicited take-over bid offer which accounted for 16% of Q3 2016 total G&A.

G&A expense per boe for the three and nine months ended September 30, 2017, increased 219% to $17.94/boe and decreased 27% to $10.93/boe compared to $5.62/boe and $14.94/boe for the 2016 comparable periods. The substantial variances based on a barrel equivalent basis are due to lower current quarter production and higher 2017 total production and greater 2017 G&A costs incurred compared to 2016.

Share-based compensation was $nil for the three and nine months ended September 30, 2017 and comparable 2016 periods as a result of no stock options being granted the past two years and the expiration and forfeiture of all previously outstanding options.

Finance (Income) and Expense

($ thousands except per boe)	Three Months Ended September 30 **2017**	2016	% Change	Nine Months Ended September 30 **2017**	2016	% Change
Interest (income)	**(6)**	(5)	20	**(17)**	(14)	21
Accretion	**1**	1	-	**3**	2	50
Financing (income)	**(5)**	(4)	25	**(14)**	(12)	17
Financing (income) ($/boe)	**(0.53)**	(0.27)	96	**0.34**	(0.50)	(32)

For the three and nine months ended September 30, 2017, the Company received $6,000 and $17,000 in interest income compared to $5,000 and $14,000 in the comparative 2016 periods. Interest income is dependent on the level of funds held on deposit. During the first nine months in both 2017 and 2016, the Company did not have bank debt and received interest on its cash balance and deposits.

Accretion is the increase or decrease, in the reporting period, in the present value of the Company's decommissioning liabilities that are estimated based on current costs, inflated at a rate of 2% and discounted using a risk free interest factor of between 1.6% and 2.4%.

Depreciation and Amortization

($ thousands except per boe)	Three Months Ended September 30 **2017**	2016	% Change	Nine Months Ended September 30 **2017**	2016	% Change
Depletion and amortization	**113**	221	(49)	**565**	287	97
Depletion and amortization ($/boe)	**11.84**	14.00	(15)	**14.36**	12.57	14

Depletion and amortization expense was $113,000 or $11.84/boe for the three months ended September 30, 2017, as compared to $221,000 or $14.00/boe in the same period in 2016 and $565,000 or $14.36/boe for the nine months ended September 30, 2017, compared to $287,000 or $12.57/boe in same period of 2016.

The significant depletion variances are attributed to lower current quarter production and higher annual production as the Pembina wells only produced for 92-days in the 2016 comparative periods as the wells were shut-in from January 19, 2016 and production restarted in Q3 on July 19, 2016. The current quarter depletion increase rate on a boe basis was impacted by impairment charges recorded in Q2 2017 which reduced the depletion base of the Company's Pembina area asset.

Impairment

($ thousands except per boe)	Three Months Ended September 30 **2017**	2016	% Change	Nine Months Ended September 30 **2017**	2016	% Change
Impairment	**1,644**	-	-	**3,599**	-	-
Impairment ($/boe)	**172.29**	-	-	**91.45**	-	-

An impairment expense is recognized for the amount by which the carrying amount exceeds the recoverable amount. Impairment expense is reversed when there has been a subsequent increase in the recoverable amount, but only to the extent of what the carrying amount would have been, had no impairment been recognized.

During the three months and nine months ended September 30, 2017, the Company recognized an impairment charge of $1,644,000 and $3,599,000 to its Pembina area CGU. The current year Pembina impairment assessment was primarily due to; a reduction in the forward commodity prices for oil (price forecast lowered by an average of 9% over the next three years); production reduction forecasts triggered by the recent water breakthrough at the 14-05 well; and current external market evaluations of similar assets, as compared to the December 31, 2016 yearend reserve report forecast prepared by the Company's independent external evaluators.

Capital Expenditures

($ thousands)	Three Months Ended September 30 **2017**	2016	% Change	Six Months Ended September 30 **2017**	2016	% Change
Drilling and completions	**-**	-	-	**-**	-	-
Facilities	**-**	-	-	**-**	(1)	(100)
Capital expenditures	**-**	-	-	**-**	(1)	(100)

Capital expenditures were $nil for the nine month period ended September 30, 2017, compared to a credit of $1,000 for the nine months ended September 30, 2016 as a result of minor facility cost adjustments at Pembina in the prior comparative period.

Capital Commitments

The Company is projected to incur approximately $140,000 for electrical upgrades and submersible pump equipping for the Pembina 9-5 and 14-5 producer wells with installation completed in October 2017 for the 14-5 well. Installation timing for the 9-5 well will be determined once the impact of the first pump installation and resultant pool performance has been assessed. Additional abandonment expenditures are forecasted to be expended in the remainder of 2017 at the Company's operated property at Dawson, Alberta and Pembina, Alberta. At Pembina, non-operated partner AFE's for reclamation work on older suspended wells have been approved and work is projected to continue. At Dawson, environmental assessment and surface reclamation work remains.

Financial Resources and Liquidity

Ironhorse's strategy is to maintain a capital structure which will sustain the Company while determining strategic alternatives available to maximize value for the shareholders. This strategy may consider future investments and acquisition opportunities, the amount of credit that may be obtainable from a lender, the availability of other sources of debt, the sale of assets, adjustments to the current capital expenditures program, and issuance of new shareholder capital. The Company's approach to managing liquidity risk is by preparing and monitoring capital and operating budgets, coordinating and authorizing project expenditures and updating when required as conditions change. The Company plans to meet its obligations when due through its available cash resources and may seek potential credit facilities in the future.

The Company's shareholders' capital is not subject to external restrictions and it does not currently have any credit facilities. The approach to capital management during the period has not changed from the prior reporting period and the Company's net working capital is as follows:

As at	**September 30, 2017**	December 31, 2016
Current assets	**3,266**	3,100
Current liabilities	**(314)**	(312)
Net working capital	**2,952**	2,788

Shareholders' Equity

At September 30, 2017, the number of common shares issued and outstanding was 27,885,824 (December 31, 2016 – 27,885,824). As at November 28, 2017, the Company had 27,885,824 common shares and no stock options issued and outstanding under its stock option plan.

Transactions with Related Parties

The Company, Grizzly Resources Ltd. (“GRL”) and Copper Island Resources Ltd. (“CIRL”) are considered related by virtue of common management. The Company and GRL are also significant joint venture partners in Ironhorse’s operating areas. The Company has entered into a management contract with GRL to provide technical and administrative services.

The Directors of the Company approved director fees and special committee fee compensation for non-management board members commencing in 2015. One of the board members is also a board member of GRL and was paid director fee compensation for the 2015 to 2017 fiscal periods.

Joint venture transactions

The nature of the joint venture transactions between GRL and Ironhorse are governed by industry standard joint operating agreements. GRL provides monthly joint interest billings to the Company which include capital expenditures, operating costs, revenues and royalty costs related to joint venture lands. Throughout the year, GRL provides the Company’s Board of Directors with information related to upcoming issues related to these joint properties to seek approval for any significant capital requirements or approval for major funding requirements that would be required by Ironhorse. The common joint venture property between the two companies is the Pembina area of Alberta.

Management fee transactions

GRL charges Ironhorse a monthly management fee for services required to manage the Company’s day to day operations. The fee is based on an estimate of accounting services, senior management services, information technology costs, reception, office rent and other general office administration. The monthly management fee for the nine months ended September 30, 2017 was $15,000 per month (September 30, 2016 - $15,000). The management agreement is reviewed annually to account for any changes in the Company’s operating assets.

For a more detailed discussion on related party transactions see note 8 of the accompanying condensed interim financial statements.

RISK FACTORS

General

Many risks are discussed below, but these risk factors should not be construed as exhaustive. There are numerous factors, both known and unknown, that could cause actual results or events to differ materially from expected results.

Depletion of reserves

Oil and natural gas operations involve many risks that, even with a combination of experience, knowledge and careful evaluation, the Company may not be able to overcome. The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Company may have at any particular time and the production there from will decline over time as such existing reserves are exploited. A future increase in the Company's reserves will depend not only on the Company’s ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that further commercial quantities of oil and natural gas will be discovered or acquired by the Company.

Financing and capital requirement

The Company's principal risks include finding and developing economic hydrocarbon reserves efficiently and being able to fund the capital program. The Company's need for capital is both short-term and long-term in nature. Short-term working capital will be required to finance accounts receivable, drilling deposits and other similar short-term assets, while the acquisition and development of oil and natural gas properties requires large amounts of long-term capital. The Company anticipates that future capital requirements will be funded through a combination of funds from operations, sale of existing assets and issuance of debt and/or equity financing. There is no assurance that debt and equity financing will be available on terms acceptable to the Company to meet its capital requirements. If any components of the Company's business plan are missing, the Company may not be able to execute the entire business plan.

Changes in Government Royalty Legislation

Provincial programs related to the oil and natural gas industry may change in a manner that adversely impacts shareholders. Ironhorse currently operates in Alberta and future amendments to royalty programs could result in a reduction of cash flows.

Regulatory Approval Risks

Before proceeding with most major development projects, Ironhorse must obtain regulatory approvals and maintain these approvals through to project completion. The regulatory approval process involves stakeholder consultation, environmental impact assessments and public hearings, among other factors. Failure to obtain regulatory approvals, or failure to obtain them on a timely basis, could result in delays, abandonment, or restructuring of projects and increased costs, all of which could negatively impact future earnings and cash flow. Failure to maintain approvals, licenses, permits and authorizations in good standing could result in the imposition of fines, production limitations or suspension orders.

Reliance on Partners

Ironhorse is dependent on other working interest partners to fund their contractual share of the capital expenditures. If these partners are unable to fund their contractual share of, or do not approve the capital expenditures, the partners may seek to defer programs, resulting in delays of portion of development of Ironhorse's programs, or the partners may default such that projects may be delayed and/or Ironhorse may be partially or totally liable for their share.

Environmental

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect to Ironhorse or its working interests. Such legislation may be changed to impose higher standards and potentially more costly obligations on Ironhorse. Furthermore, management believes that the federal political parties appear to favour new programs for environmental laws and regulations, particularly in relation to the reduction of emissions, and there is no assurance that any such programs, laws or regulations, if proposed an enacted, will not contain emission reduction targets which the Company cannot meet.

ACCOUNTING POLICIES AND ESTIMATES

Critical Accounting Estimates

We make judgements, estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Although these estimates are based on management's best knowledge of the amount, event or actions, actual results ultimately may differ from those estimates. The Company's financial and operating results incorporate estimates including:

- Estimated revenues, royalties, operating expenses on production;
- Estimated capital expenditures on projects that are in progress;
- Estimated depletion, depreciation, amortization expenses that are based on estimates of oil and gas proved and probable reserves that the Company expects to recover in the future;
- Estimated value of decommissioning liabilities that are dependent on estimates of future costs and timing of expenditures;
- Estimated future recoverable value of development and production assets within property, plant and equipment ("PP&E") and exploration and evaluation assets;
- Estimated deferred income tax assets and liabilities based on current tax interpretations, regulations and legislation that is subject to change;
- Estimated loss probable based on judgement and interpretation of laws and regulations.

The recoverable amounts of PP&E asset by area have been determined as the greater of the asset by area's value-in-use and fair value less costs to sell. These calculations require the use of estimates and assumptions and are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves and discount rates, as well as, future development and operating costs. Changes in the following assumptions used in determining the recoverable amount could affect the carrying value of the related asset.

- Reserves: Assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward price estimates, production costs or recovery rates may change the economic status of reserves and may ultimately result in reserves being restated.

- Oil and natural gas prices: Forward price estimates of the oil and natural gas prices are used in the cash flow model. Commodity prices have fluctuated widely in recent years due to global and regional factors including supply and demand fundamentals, inventory levels, exchange rates, weather, economic and geopolitical factors.

- Discount rate: The discount rate used to calculate the net present value of cash flows is based on estimates of an approximate industry peer group weighted average cost of capital. Changes in the general economic environment could result in significant changes to this estimate.

New and Future Accounting Pronouncements

IFRS 9- Financial Instruments

In July 2014, the IASB issued the final version of IFRS 9 "Financial Instruments" which replaces IAS 39, "Financial Instruments: Recognition and Measurement". The standard will come into effect for annual periods beginning on or after January 1, 2018 with earlier adoption permitted.

For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and replaces the multiple rules in IAS 39. For financial liabilities, IFRS 9 retains most of the requirements of IAS 39. In addition, IFRS 9 introduces a new expected credit loss model for calculating impairment of financial assets, replacing the incurred loss impairment model required by IAS 39. The standard also specifies standards for hedge accounts. It is anticipated that the adoption of IFRS 9 will not have a material impact on the Company's financial statements.

Amendment of IFRS 15 - Revenue Recognition

The IASB has issued IFRS 15 "Revenue from Contracts with Customers" which replaces IAS 18 "Revenue". The expectation is that IFRS 15 provides a recognition standard that can be applied consistently across various transactions, industries and capital markets. The standard specifies the five steps that an organization would apply to recognize revenue; identifying the contract with the customer, identifying the performance obligations to transfer distinct goods or services within the contract, determining the transaction price, allocating the transaction price to each separate performance obligation on the basis of relative stand-alone selling prices, and recognizing revenue when or as the performance obligation is satisfied. An organization will be considered to have satisfied a performance obligation by transferring a promised good or service to a customer with a transfer being defined in terms of when the customer obtains control of the promised good or service. IFRS 15 is effective for annual periods beginning on or after January 1, 2018. The Company is in the process of reviewing its revenue streams to determine the impact, if any, that the adoption of IFRS 15 will have on its financial statements and related disclosure.

IFRS 16 - Leases

In January 2016, The IASB issued IFRS 16 “Leases”, which replaces IAS 17 “Leases,” and provides that a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. For lessees, IFRS 16 removes the classification of leases as either operating or finance leases, effectively treating all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements, and may continue to be treated as operating leases.

IFRS 16 will come into effect for years beginning on or after January 1, 2019 with early adoption permitted if IFRS 15 “Revenue from Contracts with Customers” has been adopted. The standard may be applied retrospectively or using a modified retrospective approach. It is anticipated that the adoption of IFRS 16 will not have a material impact on the Company’s financial statements.

ADVISORY SECTION

Non-GAAP Measures

The MD&A contains terms commonly used in the oil and gas industry, such as operating netbacks (“netbacks”), funds from operations and net debt. These terms are not defined by the financial measures used by the Company to prepare its financial statements and are referred to herein as non-GAAP measures. These non-GAAP measures should not be considered an alternative to, or more meaningful than, other measures of financial performance calculated in accordance with GAAP. Management believes that in addition to net earnings (loss), netbacks, funds from operations and net debt are useful financial measurement which assist in demonstrating the Company’s ability to make interest payments, fund capital expenditures necessary for future growth or repay debt. The non-GAAP measures presented may not be comparable to that reported by other companies.

Netback

Ironhorse uses netback as a key performance indicator. Netback does not have a standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures by other companies. Netback is calculated by deducting royalties and operating expenses from petroleum and natural gas revenues.

Funds from Operations

Funds from Operations is not a recognized performance measure under GAAP and does not have a standardized meaning prescribed by GAAP. Funds from operations include cash flow from operating activities and is calculated before changes in non-cash working capital and decommissioning liabilities settled. The most comparable measure calculated in accordance with GAAP is cash flow from operating activities. The Company considers it a key measure as it demonstrates the ability of the Company to generate the funds necessary to finance future capital investments and repay debt.

The following table reconciles cash flow from operating activities to funds from operations which is used in the MD&A:

($ thousands)	**Q3 2017**	Q2 2017	Q1 2017
Cash flow from operating activities	**18**	178	75
Decommissioning expenditures (recovery)	**4**	-	4
Changes in non-cash working capital	**(129)**	(79)	101
Funds from operations	**(107)**	99	180

Net Debt

Net debt is not a recognized performance measure under GAAP and does not have a standardized meaning prescribed by GAAP. Net debt is calculated as debt and current liabilities less current assets as they appear on the balance sheet, and excludes current unrealized amounts pertaining to risk management contracts and assets held for sale and associated liabilities held for sale.

Forward-Looking Information

Statements in this MD&A that are not historical facts may be considered to be "forward looking statements." These forward looking statements sometimes include words to the effect that management believes or expects a stated condition or result. All estimates and statements that describe the Company's objectives, goals, or future plans, including management's assessment of future plans and operations, drilling plans and timing thereof, expected production rates and additions, future operating costs and the expected levels of activities may constitute forward-looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, volatility of commodity prices, imprecision of reserve estimates, environmental risks, competition from other producers, incorrect assessment of the value of acquisitions, failure to complete and/or realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and changes in the regulatory and taxation environment. As a consequence, the Company's actual results may differ materially from those expressed in, or implied by, the forward-looking statements. Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although the Company believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the ability of the Company to obtain equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Company has an interest in to operate the field in a safe, efficient and effective manor; pipeline restrictions; and field production rates and decline rates. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included elsewhere herein and in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com). Furthermore, the forward-looking statements contained in this MD&A are made as at the date of this MD&A and Ironhorse assumes no obligation to update or revise any forward-looking statements to reflect new events or circumstances, except as required by applicable laws.

BOE Conversion

In this document, certain natural gas volumes have been converted to barrels of oil equivalent ("boe") on the basis of one barrel (“bbl”) to six thousand cubic feet (“mcf”), unless otherwise stated. A conversion ratio of one bbl to six mcf is based on an energy equivalent conversion applicable at the burner tip and does not represent a value equivalency at the wellhead. Additionally, given 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 ratio of 6:1 may be misleading as an indication of value.

QUARTERLY FINANCIAL INFORMATION

The Company's operating results over the past eight quarters reflect the ongoing shift in focus as Ironhorse increases the oil weighting of its reserves and restructures its balance sheet.

($ thousands except per unit and share data)	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016	Q2 2016	Q1 2016	Q4 2015
Volumes								
Natural gas (mcf/d)	84	150	146	212	162	56	137	202
Oil & NGL (bbl/d)	90	140	140	167	145	1	44	197
Total (boe/d)	104	165	164	202	172	10	67	231
Revenues (1)	415	734	758	884	669	16	162	892
Funds from operations(2)	(107)	99	180	142	53	(94)	(131)	(144)
Per share-basic and	-	-	0.01	0.01	-	-	(0.01)	(0.01)
Net income (loss)	(3,259)	(1,522)	(33)	(700)	(123)	(69)	(144)	(2,076)
Per share-basic and	(0.12)	(0.05)	-	(0.03)	-	-	(0.01)	(0.07)
Weighted average shares								
Basic and diluted	27,886	27,886	27,886	27,886	27,886	27,886	27,886	27,886

(1) Revenues are before royalties
(2) Non-GAAP measures are defined in the Advisory section within this MD&A.