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 August 25, 2015 should be read in conjunction with the condensed financial statements for the three and six months ended June 30, 2015 and June 30, 2014 and the financial statements for the year ended December 31, 2014.

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.

2015 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.

The Company's working capital position has increased to $3.0 million at June 30, 2015, compared with $2.6 million at March 31, 2015. Higher Pembina area production in Q2 2015 increased quarterly funds from operations to $0.4 million, a 690% increase from negative funds from operations of $0.07 million in Q1 2015.

The Company recognized an impairment charge of $0.6 million related to Pembina as a result of lower prices, higher operating costs and lower production as compared to the 2014 yearend reserve report forecast. The Company's realized oil sales price, although below the forecast for 2015, increased 35% in Q2 compared to Q1, boosting operating netbacks to $22.19/boe from $3.42/boe in Q1.

OUTLOOK

During the second quarter, production from the Pembina L2L pool averaged 1,632 boe/d (gross) and is currently producing at a gross average rate of 1,840 boe/d from the 09-05 and 14-05 wells. Both wells continue to flow at restricted rates. Water injection into the 10-05 well continues at 2,800 barrels of water per day with the pool repressurized to original reservoir levels. Oil production from the two wells is anticipated to continue to be restricted due to ongoing facility and operational issues at a Sinopec operated battery and ongoing TransCanada pipeline restrictions. Plans to bring in additional blend gas are being undertaken to alleviate downtime issues. Production from the pool will be shut-in for a 10 day period in September due to a plant turnaround at Keyera MBL gas plant. Concurrent with the shut-in of production, pressure work will be undertaken on the pool wells to assist in optimizing production and waterflood performance.

SELECTED QUARTERLY INFORMATION	For the three months ended		
	June 30	March 31	June 30
($ thousands except per share amounts)	**2015**	2015	2014
Petroleum and natural gas revenues(1)	**1,262**	248	157
Funds from operations(2)	**401**	(68)	98
Net income (loss) and comprehensive income (loss)	**(634)**	(159)	51
Net (loss) per share-basic & diluted	**(0.02)**	(0.01)	-
Capital expenditures(3)	**3**	20	-
Total assets	**20,966**	21,250	21,570
Net working capital (debt)	**3,041**	2,643	2,280

(1) Petroleum and natural gas revenues are before royalty expense.
(2) Funds from operations and net debt are non-GAAP measures as defined in the Advisory section of the MD&A.
(3) Capital expenditures are before acquisitions and dispositions.

FINANCIAL AND OPERATING REVIEW

Production

	Three Months Ended June 30			Six Months Ended June 30		
	2015	2014	% Change	**2015**	2014	% Change
Light oil & NGL(bbl/d)	**215**	11	1855	**134**	9	1389
Natural gas (mcf/d)	**233**	112	108	**202**	118	71
Total (boe/d)	**254**	30	747	**168**	29	479
Volumes by product						
Oil & NGL	**85%**	38%	124	**80%**	31%	158
Natural gas	**15%**	62%	(76)	**20%**	69%	(71)

For the three months and six months ended June 30, 2015, Ironhorse's average daily light oil and NGL sales volumes were 215 bbls/d and 134 bbls/d, respectively. This represents a increase of 1855% and 1389% compared to an average sales volume of 11 bbls/d and 9 bbls/d for the same periods of 2014.

The increase in average daily sales volumes is due to the Company's Pembina Nisku light oil property producing at high rates as the Sinopec 13-2 battery expansion was completed in mid-March 2015 enabling the facility to ramp up production. Sales volumes from the 2 Pembina wells averaged 1,530 boe/d gross (239 boe/d net) during Q2 2015. Production was expected to be higher during Q2 however, the completion of the 13-2 battery expansion and final facility testing reduced the 14-5 flow rates. There was also unexpected downtime at third party facilities which contributed to reduced production during the months of April and June. The Company is continuing to work with partners to optimize the Nisku pool production by managing reservoir pressure, water injection schemes and the blend gas stream to increase production capabilities and improve operating netbacks. Based on forecasted operational plans, including a Keyera MBL facility turnaround in September, production at Pembina is anticipated to average in the range of 275 to 300 boe/d (net) during Q3 2015.

Natural gas sales volumes for the three and six months ended June 30, 2015, were 233 mcf/d and 202 mcf/d respectively representing an increase of 108% and 71% compared to an average sales volume of 112 mcf/d and 118 mcf/d for the same periods of 2014. This three and six month to date variance is due to the Company's increased Pembina production as discussed above, offset by reduced production from the natural gas well at Balsam, Alberta. 2015 gas production is comprised of 54% from Pembina and 46% from Balsam.

Commodity Prices

	Three Months Ended June 30			Six Months Ended June 30		
	2015	2014	% Change	**2015**	2014	% Change
Average benchmark prices:						
WTI (US$/bbl)	**57.94**	102.99	(44)	**53.29**	100.84	(47)
Canadian Light Sweet ($/bbl)	**68.88**	104.14	(34)	**61.08**	101.95	(40)
AECO natural gas ($/mcf)(1)	**2.67**	4.70	(43)	**2.71**	5.16	(47)
Realized prices:						
Light oil & NGL ($/bbl)	**61.80**	102.67	(40)	**58.57**	101.69	(42)
Natural gas ($/mcf)	**2.57**	5.08	(49)	**2.51**	5.52	(55)
Total ($/boe)	**54.70**	57.59	(5)	**49.81**	55.31	(10)

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

Revenues

($ thousands)	Three Months Ended June 30 **2015**	2014	% Change	Six Months Ended June 30 **2015**	2014	% Change
Light oil & NGL	**1,207**	105	1,050	**1,418**	173	720
Natural gas	**55**	52	6	**92**	118	(22)
Total	**1,262**	157	704	**1,510**	291	419

Revenues and Commodity Prices

The Company's realized light oil and NGL price/bbl for the three and six months ended June 30, 2015, was 40% and 42% lower respectively compared to the same periods in 2014 and on par with the benchmark Canadian Light Sweet price percentage decreases. Subsequent to June 30, the Canadian Light Sweet average oil benchmark price for July 2015 decreased approximately 15% to $61/bbl from the June 2015 price and 12% from the Q2 2015 average benchmark price.

The Company’s realized natural gas price/mcf for the three months and six months ended June 30, 2015 was 49% and 55% lower respectively compared to the same periods in 2014. The benchmark natural gas price decreased 43% and 47% for the three months and six months ended June 30, 2015 compared to the same periods in 2014. 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 June 30, 2015 was $1,262,000 a 704% increase from the $157,000 for the three months ended June 30, 2014. Revenues for the six months ended June 30, 2015 increased by 419% from $291,000 to $1,510,000. This increase in sales revenue for both the three months and six months ended June 30, 2015 was a result of higher sales volumes from the Pembina Nisku wells as compared to 2014 that had restricted production due to insufficent blend gas being available when the Nisku wells were brought on stream in March of 2014.

Royalties

($ thousands except per boe)	Three Months Ended June 30 **2015**	2014	% Change	Six Months Ended June 30 **2015**	2014	% Change
Oil & NGL	**360**	24	1,400	**448**	29	1,445
Natural gas	**11**	(34)	(132)	**24**	(11)	(318)
Royalties	**371**	(10)	(3,810)	**472**	18	2,522
Royalties %	**29**	(6)	(583)	**31**	6	417
Royalties per boe	**16.07**	(3.53)	(555)	**15.56**	3.41	356

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 June 30, 2015, royalties increased 3,810% from a recovery of $10,000 in the comparable period in 2014 to $371,000. The recovery in 2014 was related to $44,000 of gas cost allowance and custom processing fee credits received related to natural gas crown royalties previously paid. Royalties as a percentage of revenues increased to 29% for the three months ended June 30, 2015 compared to a recovery of 6% in the comparable period in 2014.

Royalties as a percentage of revenues increased 417% to 31% for the six months ended June 30, 2015 compared to the same period in 2014. This increase is primarily a result of the Pembina 14-5's oil royalty rate increasing to a sliding scale maximum of 40% from 5% in Q2. The Pembina wells qualified for the new well royalty rate which allows for a 5% royalty on the first 50,000 barrels of gross production or 12 producing months, whichever occurs first. Once either of these conditions is met, the royalty rate reverts to a maximum of 40%, based on monthly price and production volumes. Both wells have now exceeded the minimum royalty rate production qualification.

Operating Expenses

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except per boe)	**2015**	2014	% Change	**2015**	2014	% Change
Operating expenses	**380**	31	1,126	**502**	61	723
Operating expenses ($/boe)	**16.44**	11.36	45	**16.55**	11.56	43

Operating expenses were $380,000 or $16.44/boe, for the three months ended June 30, 2015 compared to $31,000 or $11.36/boe for the comparable period in 2014 representing an increase of 1,126% and 45% respectively. For the six months ended June 30, 2015 operating costs increased by 723% to $502,000 or $16.55/boe compared to $61,000 or $11.56/boe compared to the same period in 2014.

The increase in operating expenses is due to higher Pembina production levels in 2015 compared to 2014. Once the upgrade of the Sinopec 13-2 battery was completed in March 2015, the Pembina wells were able to produce at much higher rates. These higher rates require higher amounts of blend gas volumes to sweeten the solution gas produced from Pembina wells to meet licensed pipeline specifications due to the high hydrogen sulphide (H2S) content. The associated blend gas costs account for over 70% of total 2015 operating costs. The Company is actively working with its partners to identify opportunities to reduce costs associated with sourcing blend gas requirements needed for Pembina production.

Operating Netbacks

	Three Months Ended June 30			Six Months Ended June 30		
	2015	2014	% Change	**2015**	2014	% Change
Oil & NGL ($/bbl)	**61.80**	102.67	(40)	**58.57**	101.69	(42)
Natural gas ($/mcf)	**2.57**	5.08	(49)	**2.51**	5.52	(55)
Revenues ($/boe)	**54.70**	57.59	(5)	**49.81**	55.31	(10)
Royalties ($/boe)	**(16.07)**	3.53	(555)	**(15.56)**	(3.41)	356
Operating expenses ($/boe)	**(16.44)**	(11.36)	45	**(16.55)**	(11.56)	43
Operating netback ($/boe)	**22.19**	49.76	(55)	**17.70**	40.34	(56)

Ironhorse's operating netback per boe for the three months ended June 30, 2015 decreased by 55% from the three months ended June 30, 2014. For the six months ended June 30, 2015, operating netback was $17.70/boe compared to $40.34/boe in the same period in 2014 representing a 56% decrease. Realized oil and liquids prices decreased 40% and 42% for the three and six months ended June 30, 2015 respectively as a result of commodity price declines.

The decreased netback in 2015 is the result of higher operating costs, increased crown royalties and lower commodity prices as compared with 2014. The higher 2015 production weighted to oil compared to 2014, reduced the impact of declining commodity prices on a revenue per boe basis. Operating costs increased 45% and 43% for the three and six months ended June 30, 2015 as higher operating costs attributed primarily to the Pembina associated blend gas costs as oil production ramped up over 1,300% in comparison to 2014. The royalty rate increase is a result of the initial minimum royalty rates for Pembina reverting to higher rates, as well as increased production as previously discussed.

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

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except per boe)	**2015**	2014	% Change	**2015**	2014	% Change
G&A expense	**114**	160	(29)	**211**	280	(25)
Share-based compensation	**-**	1	(100)	**-**	(2)	(100)
G&A expense ($/boe)	**4.94**	58.85	(92)	**6.96**	53.29	(87)
Share-based comp ($/boe)	**-**	0.37	(100)	**-**	(0.38)	(100)

G&A expense for the three months ended June 30, 2015 decreased 29% to $114,000 from $160,000 for the three months ended June 30, 2015. G&A expenses for the six months ended June 30, 2015 decreased 25% to $211,000 from $280,000 for the same period in 2014. This decrease in both periods is a result of monthly management fees which were reduced to $15,000 per month for 2015 as compared with $25,000 per month in 2014, along with reduced consulting fees incurred in 2015.

The Directors of the Company approved director fees and special committee fee compensation for non-management board members commencing with the first quarter of 2015. Quarterly director fee compensation is $2,500 per board member. Members of the Special Committee, formed in 2015 to review strategic alternatives, will receive fees of $10,000, with the Committee chair receiving $15,000. Accrued fees of $18,750 related to the first half of 2015 have been included in the reported G&A expense to date.

G&A expense per boe for the three and six months ended June 30, 2015 decreased 92% to $4.94/boe and 87% to $6.96/boe compared to $58.85/boe and $53.29/boe for the 2014 comparable periods. The substantial decrease is due to higher production in 2015 compared to 2014.

Share-based compensation was $nil for the three and six months ended June 30, 2015 compared to $1,000 and a recovery of $2,000 for the comparative 2014 periods as a result of no stock options being granted in the past two years and the expiration and forfeiture of options during 2014.

Finance (Income) expense

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except per boe)	**2015**	2014	% Change	**2015**	2014	% Change
Interest (income) expense	**(4)**	(5)	(20)	**(8)**	(10)	(20)
Accretion	**1**	1	-	**2**	3	(33)
Finance (income) expense	(3)	(4)	(25)	**(6)**	(7)	(14)
Finance (income) expense $/boe	**(0.14)**	(1.47)	(91)	**(0.20)**	(1.33)	(85)

For the three and six months ended June 30, 2015 the Company received $4,000 and $8,000 in interest income compared to $5,000 and $10,000 in the comparative 2014 periods. Interest income is dependent on the level of funds held on deposit. During the first six months in both 2015 and 2014, 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 0.6% and 2.3%.

Depletion and amortization

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except per boe)	**2015**	2014	% Change	**2015**	2014	% Change
Depletion and amortization	**521**	44	1,084	**663**	82	709
Depletion and amortization ($/boe)	**22.59**	16.18	40	**21.88**	15.61	40

Depletion and amortization expense was $521,000 or $22.59/boe for the three months ended June 30, 2015 as compared to $44,000 or $16.18/boe in the same period in 2014 and $663,000 or $21.88/boe for the six months ended June 30, 2015 compared to $82,000 or $15.61/boe for the same period in 2014. In both cases, the increase in depletion is due to significantly higher production in 2015 as compared to 2014 from the Company's Pembina area, offset by less production at Balsam.

Impairment

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except per boe)	**2015**	2014	% Change	**2015**	2014	% Change
Impairment	**608**	1	60,700	**609**	3	20,200
Impairment ($/boe)	**26.37**	0.37	7,027	**20.09**	0.57	3,425

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 month period ended June 30, 2015, the company recognized an impairment charge of $609,000 to its Pembina area CGU as a result of higher than anticipated operating costs, lower realized sales revenues and lower production as compared to the 2014 yearend reserve report forecast. The higher operating costs are mainly attributed to the blending fees and handling costs related to the high H2S content of the solution gas produced.

Income Taxes

During the second quarter of 2015, the Alberta government enacted legislation increasing the provincial corporate income tax rate from 10% to12% effective July 1, 2015. As a result of this income tax rate increase, the Company's deferred income tax liability was increased by $87,000 in the current quarter.

Capital Expenditures

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2015**	2014	% Change	**2015**	2014	% Change
Drilling and completions	**3**	-	-	**18**	397	(95)
Facilities	**-**	-	-	**5**	239	(98)
Capital expenditures	**3**	-	-	**23**	636	(96)

Capital expenditures totalled $23,000 for the six months ended June 30, 2015 compared to $636,000 for six months ended June 30, 2014. Capital expenditures for the current period are related to facility costs at the 7-5 Pembina pad site and recompletion costs related to the Pembina Nisku production and injection wells.

Capital expenditures for the 2014 comparative period included $321,000 of drilling and down hole abandonment costs for the Pembina Nisku 1-8 well; $239,000 of facility costs related to the Pembina Nisku production and injection wells; $76,000 in completion costs related to the Pembina Nisku production wells

Shareholders' Equity

As at June 30, 2015 there were 27,885,824 shares outstanding and 540,000 options outstanding with a weighted average strike price of $0.33.

	Number of shares	Amount
Balance, December 31, 2014 and June 30, 2015	27,885,824	29,875

During the six months ended June 30, 2015 there were no option grants and 201,000 options that had expired or were forfeited. During the three month period ended March 31, 2014 there were 25,000 options exercised at a price of $0.17 per option.

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 as a result of changes in reserve values, 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 Company's net working capital is as follows:

($ thousands) **As at**	**June 30, 2015**	December 31, 2014
Current assets	**3,835**	3,027
Current liabilities	**(794)**	(296)
Net working capital	**3,041**	2,731

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.

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 six months ended June 30, 2015 was $15,000 per month (June 30, 2014 - $25,000). 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 Corporation'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 PP&E and E&E 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

As of January 1, 2014, Ironhorse adopted the following standards and amendments issued by the IASB. The adoption of these standards did not have any material impact on the Company's financial statements.

- IAS 36 "Impairment of Assets" which reduce the circumstances in which the recoverable amount of CGUs is required to be disclosed and clarify the disclosures required when an impairment loss has been recognized or reversed in the period.

- IFRIC 21 "Levies," which was developed by the IFRS Interpretations Committee ("IFRIC"). IFRIC 21 clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. It also clarifies that no liability should be recognized before the specified minimum threshold to trigger that levy is reached.

IFRS 9- Financial Instruments

The IASB intends to replace International Accounting Standards ("IAS") 39, "Financial Instruments: Recognition and Measurement" with IFRS 9, "Financial Instruments". 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. Portions of the standard remain in development and the full impact of the standard on the Company's financial statements is tentatively required to be adopted for fiscal years beginning January 1, 2018.

IFRS 11- Joint Arrangements

IFRS 11 Joint arrangements has been amended to require that the relevant principles from IFRS 3 Business combinations be applied when an organization acquires an initial or additional interest in a joint operation and the activities of the joint operation constitute a business as defined in IFRS 3. IFRS 1 is effective for annual periods beginning on or after January 1, 2016.

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 report 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)	**Q2 2015**	Q1 2015	Q2 2014
Cash flow from operating activities	**200**	190	(169)
Decommissioning expenditures	**-**	-	-
Changes in non-cash working capital	**201**	(258)	267
Funds from operations	**401**	(68)	98

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

Certain information regarding Ironhorse set forth in this document, including management's assessment of the Company's future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. These forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond Ironhorse's control. These risks include, but are not limited to, operational risks in development, exploration, production and start-up activities; delays and changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainly of estimates and projections relating to production, costs and expenses, and environmental risks, risks associated with the impact of industry conditions, volatility of commodity prices, currency fluctuations, competition from other producers, ability to access capital from internal and external sources. Ironhorse's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what impact it would have on Ironhorse. Words such as “may”, “will”, “should”, “could”, “anticipate”, “believe”, “expect”, “intend”, “plan”, “potential”, “continue”, and similar expressions have been used to identify these forward-looking statements.
The forward-looking information contained in this MD&A are as of the date of the MD&A and Ironhorse assumes no obligation to update or revise any forward-looking information 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)	Q2 2015	Q1 2015	Q4 2014	Q3 2014	Q2 2014	Q1 2014	Q4 2013	Q3 2013
Volumes								
Natural gas (mcf/d)	233	171	150	130	112	124	159	285
Oil & NGL (bbl/d)	215	52	77	64	11	8	9	41
Total (boe/d)	254	81	102	86	30	28	36	89
Revenues (1)	1,262	248	545	593	157	134	130	441
Funds from operations(2)	401	(68)	123	358	98	(44)	(73)	24
Per share-basic and diluted	0.01	-	0.01	0.01	-	-	-	-
Net income (loss)	(634)	(159)	(331)	141	51	(82)	26	(1,015)
Per share-basic and diluted	(0.02)	(0.01)	(0.01)	0.01	-	-	(0.01)	(0.03)
Weighted average shares								
Basic and diluted	27,886	27,886	27,886	27,886	27,886	27,886	27,861	27,861

(1) Revenues are before royalties

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

IRONHORSE OIL & GAS INC.
CONDENSED INTERIM FINANCIAL STATEMENTS
(UNAUDITED)
FOR THREE AND SIX MONTHS ENDED JUNE 30, 2015 AND 2014

MANAGEMENT'S REPORT

The accompanying unaudited interim condensed financial statements of Ironhorse Oil & Gas Inc. (the "Company") for the three and six months ended June 30, 2015 and 2014 have been prepared by management and were approved by the Board of Directors of the Company. These financial statements have not been reviewed by the Company's external auditors.

Dated August 25, 2015

Approved on behalf of Ironhorse Oil & Gas Inc.:

(signed) "Larry J. Parks"	(signed) "Karen Hutson"
Larry J. Parks	Karen Hutson
President & Chief Executive Officer	VP Finance & Chief Financial Officer

IRONHORSE OIL & GAS INC.
Condensed Interim Statements of Financial Position
(Unaudited)
(In thousands of Canadian dollars)

	June 30, 2015	December 31, 2014
ASSETS		
Current assets		
Cash	**2,828**	2,469
Accounts receivable	**736**	278
Prepaid expenses and deposits	**271**	280
	3,835	3,027
Property, plant and equipment (note 3)	**17,131**	18,382
	20,966	21,409
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**794**	296
Decommissioning liabilities (note 4)	**331**	331
Deferred income taxes	**1,180**	1,328
	2,305	1,955
SHAREHOLDERS' EQUITY		
Shareholders' capital (note 5)	**29,875**	29,875
Contributed surplus	**2,048**	2,048
Deficit	**(13,262)**	(12,469)
	18,661	19,454
	20,966	21,409

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

Approved on behalf of the Board:

(signed) "Larry J. Parks"
____
Director

(signed) "Gerry C. Quinn"
____
Director

IRONHORSE OIL & GAS INC.
Condensed Interim Statements of Income (Loss)
(Unaudited)

(In thousands of Canadian dollars except per share amounts)

	Three months ended June 30		Six months ended June 30	
	2015	2014	**2015**	2014
REVENUES				
Petroleum and natural gas revenues, gross	**1,262**	157	**1,510**	291
Royalties	**(371)**	10	**(472)**	(18)
	891	167	**1,038**	273
EXPENSES				
Operating and transportation	**380**	31	**502**	61
General and administrative expense	**114**	160	**211**	280
Share-based compensation (note 5)	**-**	1	**-**	(2)
Finance (income) expense (note 6)	**(3)**	(4)	**(6)**	(7)
Depletion and amortization (note 3)	**521**	44	**663**	82
Impairment	**608**	1	**609**	3
Gain on disposition of properties (note 3)	**-**	(119)	**-**	(114)
	1,620	114	**1,979**	303
Net income (loss) before income taxes	**(729)**	53	**(941)**	(30)
Income taxes	**-**	2	**-**	2
Deferred income tax recovery (note 9)	**(95)**	-	**(148)**	(1)
Net income (loss) and comprehensive income (loss)	**(634)**	51	**(793)**	(31)
Deficit, beginning of the period	**(12,628)**	(12,330)	**(12,469)**	(12,248)
Deficit, end of the period	**(13,262)**	(12,279)	**(13,262)**	(12,279)
Net (loss) per share (note 5)				
Basic and diluted	**(0.02)**	-	**(0.03)**	-

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

IRONHORSE OIL & GAS INC.
Condensed Interim Statement of Changes in Equity
(Unaudited)
(In thousands of Canadian dollars)

	Shareholders' Capital	Contributed Surplus	Deficit	Total Equity
Balance as at December 31, 2013	29,869	2,051	(12,248)	19,672
Share-based compensation	-	(2)	-	(2)
Share issuance	6	(2)	-	4
Net loss	-	-	(31)	(31)
Balance as at June 30, 2014	29,875	2,047	(12,279)	19,643
Balance as at December 31, 2014	29,875	2,048	(12,469)	19,454
Net loss	-	-	(793)	(793)
Balance as at June 30, 2015	29,875	2,048	(13,262)	18,661

The accompanying notes are an integral part of these condensed interim financial statements

IRONHORSE OIL & GAS INC.
Condensed Interim Statement of Cash Flows
(Unaudited)
(In thousands of Canadian dollars)

	Three months ended June 30		Six months ended June 30	
	2015	2014	**2015**	2014
Cash flows from operating activities				
Net income (loss)	**(634)**	51	**(793)**	(31)
Items not affecting cash:				
Depletion and amortization (note 3)	**521**	44	**663**	82
Impairments (note 3)	**608**	1	**609**	3
Accretion of decommissioning liabilities (note 4)	**1**	1	**2**	3
Share-based compensation (note 5)	**-**	1	**-**	(2)
Deferred income tax recovery	**(95)**	-	**(148)**	(1)
Net change in decommissioning liabilities (note 4)	**-**	-	**-**	(2)
Change in non-cash working capital (note 10)	**(201)**	(267)	**57**	(101)
Net change from cash flows from operating activities	**200**	(169)	**390**	(49)
Cash flows from financing activities				
Cash received on the exercise of stock options	**-**	-	**-**	4
	-	-	**-**	4
Cash flows from investing activities				
Property, plant and equipment expenditures (note 3)	**(3)**	-	**(23)**	(636)
Changes in non-cash working capital (note 10)	**(20)**	(1,593)	**(8)**	(821)
	(23)	(1,593)	**(31)**	(1,457)
Increase (Decrease) in cash	**177**	(1,762)	**359**	(1,502)
Cash, beginning of the period	**2,651**	3,920	**2,469**	3,660
Cash, end of the period	**2,828**	2,158	**2,828**	2,158
Supplemental cash information:				
Interest expense paid (received)	**(4)**	(3)	**(8)**	(10)
Income taxes paid	**-**	-	**-**	-

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

1. REPORTING ENTITY

Ironhorse Oil & Gas Inc. ("Ironhorse" or the "Company") is incorporated under the Business Corporations Act of Alberta with its principal place of business at 1000, 324-8th Avenue SW, Calgary, Alberta. The Company's shares are listed on the TSX Venture Exchange under the symbol IOG-V. Ironhorse is engaged in the exploration for, development and production of petroleum and natural gas reserves in western Canada.

2. BASIS OF PRESENTATION

(a) Statement of Compliance

The condensed financial statements (the "financial statements") have been prepared in accordance with IAS 34, "*Interim Financial Reporting"* using accounting policies consistent with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). The Company's significant accounting policies are the same as those disclosed in Note 3 of the Company's audited financial statements as at and for the years ended December 31, 2014 and 2013. These condensed interim financial statements do not include all of the information required for full annual financial statements.

These financial statements were authorized for issuance in accordance with a resolution of the Board of Directors on August 25, 2015.

(b) New Accounting Standards

As of January 1, 2014, Ironhorse adopted the following standards and amendments issued by the IASB. The adoption of these standards did not have any material impact on the Company's financial statements.

- IAS 36 "Impairment of Assets" which reduce the circumstances in which the recoverable amount of CGUs is required to be disclosed and clarify the disclosures required when an impairment loss has been recognized or reversed in the period.

- IFRIC 21 "Levies," which was developed by the IFRS Interpretations Committee ("IFRIC"). IFRIC 21 clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. It also clarifies that no liability should be recognized before the specified minimum threshold to trigger that levy is reached.

IFRS 9- Financial Instruments
The IASB intends to replace International Accounting Standards ("IAS") 39, "Financial Instruments: Recognition and Measurement" with IFRS 9, "Financial Instruments". 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. Portions of the standard remain in development and the full impact of the standard on the Company's financial statements is tentatively required to be adopted for fiscal years beginning January 1, 2018.

IFRS 11- Joint Arrangements
IFRS 11 Joint arrangements has been amended to require that the relevant principles from IFRS 3 Business combinations be applied when an organization acquires an initial or additional interest in a joint operation and the activities of the joint operation constitute a business as defined in IFRS 3. IFRS 1 is effective for annual periods beginning on or after January 1, 2016.

3. PROPERTY, PLANT AND EQUIPMENT ("PP&E")

PP&E – Cost	
Balance, December 31, 2013	22,955
Additions	666
Changes in decommissioning liabilities	9
Balance, December 31, 2014	23,630
Additions	23
Changes in decommissioning liabilities	(2)
Balance, June 30, 2015	**23,651**

Accumulated depletion and amortization	
Balance, December 31, 2013	(4,419)
Depletion and amortization expense	(473)
Impairment	(356)
Balance, December 31, 2014	(5,248)
Depletion and amortization expense	(663)
Impairment	(609)
Balance, June 30, 2015	**(6,520)**

Carrying value	
As at December 31, 2014	18,382
As at June 30, 2015	**17,131**

During the six months ended June 30, 2014 the Company realized a gain for its share of a recovery of operating expenses related to its Shackleton property that was sold in a prior period and post-closing cost adjustments related to the Leon Lake property.

Impairment

For the six month period ended June 30, 2015, the Company recorded an impairment loss of $609,000 against PP&E related to its Pembina CGU (2014 - $3,000 other CGU). The impairment loss was due to a decrease in the value-in-use triggered primarily by a rise in operating costs and reduced production performance in 2015 as compared to the December 31, 2014 external reserve report forecast.

The recoverable amount for the Pembina CGU is $17.1 million and the value-in-use was determined by the net present value of the before tax cash flows from oil, natural gas and liquids proved plus probable reserves estimated by the Company's external reserve evaluators, discounted at a rate of 10%.

4. DECOMMISSIONING LIABILITIES

	June 30, 2015	December 31, 2014
Balance, beginning of period	**331**	322
Change in estimates and discount rate	**(2)**	9
Settlement of decommissioning liabilities	**-**	(2)
Accretion expense	**2**	2
Balance, end of period	**331**	331

5. SHAREHOLDERS' CAPITAL

The Company has authorized an unlimited number of common shares and first preferred shares. The outstanding shareholders' capital is as follows:

(a) Issued

	Number of Shares	Amount
Balance, December 31, 2014 and June 30, 2015	27,885,824	29,875

(b) Share based compensation

During the six months ended June 30, 2015 no options were granted, 186.000 options expired, and 15,000 options were forfeited. As at June 30, 2015 there were 540,000 options outstanding with a weighted average strike price of $0.33.

(c) Per Share Amounts

For six months ended June 30	**2015**	2014
Basic and Diluted :		
Loss per share	**(0.03)**	-
Weighted average common shares – basic	**27,885,824**	27,885,824
Weighted average common shares – diluted	**27,885,824**	27,885,824

6. FINANCE (INCOME) EXPENSE

For six months ended June 30	**2015**	2014
Interest (income) expense and finance charges	**(8)**	(10)
Accretion and decommissioning liabilities (note 4)	**2**	3
	(6)	(7)

7. CAPITAL MANAGEMENT

The Company's shareholders' capital is not subject to external restrictions. The Company does not have any credit facilities and there were no changes in the Company's approach to capital management during the period. The Company's net working capital is as follows.

As at	**June 30, 2015**	December 31, 2014
Current assets	**3,835**	3,027
Current liabilities	**(794)**	(296)
Net working capital	**3,041**	2,731

8. RELATED PARTY TRANSACTIONS

Management fee transactions

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.

A summary of related party transactions included in the financial statements are as follows:

For the six months ended June 30	**2015**	2014
Capital expenditures	**29**	1,529
Operating expenses	**(14)**	14
Petroleum and natural gas revenues	**1,460**	146
Royalties	**362**	14
Net gain on disposition of properties	**-**	111
General and administrative – management fees	**90**	150

The inter-company net receivable balances due from related parties were as follows:

As at June 30	**2015**	2014
Grizzly Resources Ltd.	**675**	175

The amounts outstanding at June 30, 2015 were settled by July 31, 2015

Director fees

During the second quarter of 2015, the Directors of the Company authorized director fees and special committee fee compensation for non-management board members, commencing with the first quarter of 2015. Director fees of $5,000 have been recorded during the first six months of 2015 related to a member of the Board of Directors who is also a director of Grizzly Resources Ltd.

9. INCOME TAXES

During the second quarter of 2015, the Alberta government enacted legislation increasing the provincial corporate income tax rate from 10% to 12% effective July 1, 2015. As a result of this income tax rate increase, the Company's deferred income tax liability was increased by $87,000 in the current quarter.

10. SUPPLEMENTAL DISCLOSURES

For the six months ended June 30	**2015**	2014
Changes in non-cash working capital:		
Accounts receivable	**(458)**	265
Prepaid expenses	**9**	-
Accounts payable and accrued liabilities	**498**	(1,187)
	49	(922)
Relating to:		
Operating activities	**57**	(101)
Investing activities	**(8)**	(821)
	49	(922)