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 April 7, 2016, should be read in conjunction with the financial statements for the years ended December 31, 2015 and 2014.

This MD&A and financial statements and comparative information have been prepared in Canadian dollars, except where another currency has been indicated. The MD&A and financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB).

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 exploration, 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 funds from operations decreased 57% to $228 thousand in 2015, compared to $535 thousand in 2014 despite a 216% increase in production as operating netbacks descended 67% to $12.61/boe (2014 - $38.58). Netbacks were weakened by declining commodity prices and higher royalties and operating costs compared to 2014. Cash flows were also substantially reduced as a result of $270 thousand in general and administrative costs incurred in Q4 2015 in defense of the unsolicited take-over bid by 1927297 Alberta Ltd.

The Company realized a net loss of $5.7 million (loss of $0.21 per share) for the year primarily resulting from a $6.4 million impairment charge at Pembina, lower netbacks and partially offset by a $2 million non-cash deferred tax recovery.

Combined sales from the Nisku L2L pool ("the Pool") 9-5 and 14-5 wells averaged 1,184 boe/d gross (185 boe/d net), an increase of over 300% compared to 2014. Production was restricted for seven months throughout 2015 as Sinopec Daylight Energy Ltd. ("Sinopec"), the operator of pipelines and facilities associated with production from the Pool, did not complete facility upgrades and testing of their 13-2 battery until late March restraining Q1 production, a 20-day third party Keyera gas plant turnaround in September and TransCanada ("TCPL") pipeline curtailments in Q4 that limited handling capacity of gas for the remainder of the year.

A Special Committee comprised of independent directors of the Company was established to review and consider potential options available in order to maximize shareholder value. Any potential corporate or asset transactions that may result as part of this review will depend on market conditions and will require shareholder approval prior to finalization.

OUTLOOK

On January 19, 2016 the operator of the Pool shut-in the Pembina wells because production is uneconomic under the current commodity price environment. The Company believes that, with continued downward pressure on commodity prices, a temporary shut-in of the Pool production is a prudent decision that will preserve the value of Ironhorse's oil and natural gas reserves. The Company anticipates that the Pool will remain shut-in until there is a recovery in commodity prices.

Notwithstanding suspension of its main source of cash flow, Ironhorse is financially well positioned, with existing positive working capital and no debt.

Lawsuit – Statement of Claim Filed

On February 23, 2016, the Company and Grizzly Resources Ltd. ("GRL"), the operator of the Pool, 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.

UNSOLICITED TAKE-OVER BID

On November 4, 2015, an unsolicited all cash take-over bid (the "Offer") was commenced by 1927297 Alberta Ltd. (the "Offeror"), a corporation wholly-owned by Timmerman Trust, to acquire the outstanding common shares of Ironhorse for $0.17 per share.

The Board of Directors carefully reviewed and considered the Offer, with the benefit of advice from Ironhorse's financial and legal advisors and unanimously recommended that Ironhorse shareholders reject the Offer.

Additional information can be found in the Ironhorse Directors' Circular dated November 19, 2015, which was sent to all Ironhorse shareholders.

On February 5, 2016 the Offer expired as the minimum tender condition of the Offer was not met and the Offeror did not take up any shares deposited under the Offer.

The Company has incurred approximately $325,000 as at March 31, 2016 in total general and administrative costs related to the take-over-bid.

SELECTED ANNUAL INFORMATION

		Years Ended December 31	
($ thousands except per share amounts)	**2015**	2014	2013
Petroleum and natural gas revenues(1)	**3,343**	1,429	1,590
Funds from operations(2)	**228**	535	(4)
Net (loss)	**(5,719)**	(221)	(1,713)
Net (loss) per share-basic & diluted	**(0.21)**	(0.01)	(0.06)
Capital expenditures(3)	**44**	666	870
Total assets	**15,206**	21,409	22,776
Net working capital (debt)(2)	**2,915**	2,731	2,860

(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 December 31			Year Ended December 31		
	2015	2014	% Change	**2015**	2014	% Change
Natural gas (mcf/d)	**202**	150	35	**192**	129	49
Light oil & NGL(bbl/d)	**197**	77	156	**164**	40	310
Total (boe/d)	**231**	102	126	**196**	62	216
Volumes by product						
Natural gas	**15%**	24%	(38)	**16%**	36%	(56)
Oil & NGL	**85%**	76%	12	**84%**	64%	31

For the three months and year ended December 31, 2015 Ironhorse's average daily light oil and NGL sales volumes were 197 bbls/d and 164 bbls/d, respectively. This represents an increase of 156% and 310% compared to an average sales volume of 77 bbls/d and 40 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. Production was expected to be higher during Q4 2015 and Q3 2015; however TCPL pipeline restrictions and the September Keyera Minnehik Buck Lake planned facility turnaround lasted 10 days longer than anticipated due to unexpected repairs being required and as a result, Pembina net sales averaged 190 boe/d during the remaining 4 months of 2015.

Natural gas sales volumes for the three months and year ended December 31, 2015 were 202 mcf/d and 192 mcf/d respectively representing an increase of 35% and 49% compared to an average sales volume of 150 mcf/d and 129 mcf/d for the same periods of 2014. The three month and year to date variance is due to Pembina's increased production as discussed above, offset partially by reduced production from the natural gas well at Balsam, Alberta which was shut-in during Q3 due to high transportation costs. 2015 gas production is comprised of 72% from Pembina and 28% from Balsam.

2015 sales volumes from the two Pembina wells reached a milestone rate of 1,850 boe/d gross (289 boe/d net) during the month of August and the three highest producing months averaged 1,779 boe/d gross (277 boe/d net) highlighting the solid production potential of the Pool wells.

On January 19, 2016 the operator of the Pool shut-in the Pembina wells because production is uneconomic under the current commodity price environment. The Company believes that, with continued downward pressure on commodity prices, a temporary shut-in of the Pool production is a prudent decision that will preserve the value of Ironhorse's oil and natural gas reserves. The Company anticipates that the Pool will remain shut-in until there is a recovery in commodity prices.

Commodity Prices

	Three Months Ended December 31			Year Ended December 31		
	2015	2014	% Change	**2015**	2014	% Change
Average benchmark prices						
AECO natural gas ($/mcf) (1)	**2.48**	3.63	(32)	**2.70**	4.50	(40)
WTI (US$/bbl)	**42.18**	73.15	(42)	**48.80**	93.00	(48)
Canadian Light Sweet ($/bbl)	**52.55**	74.38	(29)	**57.45**	93.99	(39)
Realized prices						
Natural gas ($)	**2.44**	3.55	(31)	**2.53**	4.60	(45)
Light oil & NGLs ($)	**46.78**	69.58	(33)	**53.02**	82.01	(35)
Total ($)	**42.08**	57.84	(27)	**46.83**	63.16	(26)

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

Revenues

	Three Months Ended December 31			Year Ended December 31		
($ thousands)	**2015**	2014	% Change	**2015**	2014	% Change
Natural gas	**45**	49	(8)	**177**	217	(18)
Light oil & NGLs	**847**	496	71	**3,166**	1,212	161
Total	**892**	545	64	**3,343**	1,429	134

Revenues and Commodity Prices

The Company's realized light oil and NGL price/bbl for the three months and year ended December 31, 2015 were 33% and 35% lower respectively compared to the same periods in 2014 and reflective of the continued commodity price downturn. The Company's realized oil sales prices differ from posted prices due to quality and transportation differentials. The Company's realized natural gas price/mcf decreased by 45% for 2015 as compared with 2014 and trended reasonably close to the AECO spot price annual averages.

Subsequent to December 31, 2015, the average Canadian Light Sweet oil benchmark price for the first two months of 2016 continued to deteriorate, decreasing 17% averaging $39.66/bbl compared to December.

Sales revenues for the three months ended December 31, 2015 were $892,000, a 64% increase from the $545,000 for the three months ended December 31, 2014. Revenues for the year ended December 31, 2015 increased by 134% from $1,429,000 to $3,343,000. The increase in Q4, and for the year, was the result of higher oil sales volumes during the year offset partially by decreased natural gas sales volumes and as discussed previously.

Royalties

	Three Months Ended December 31			Year Ended December 31		
($ thousands except per boe)	**2015**	2014	% Change	**2015**	2014	% Change
Natural gas	**14**	7	100	**45**	(16)	(381)
Oil & NGL	**368**	161	128	**1,213**	242	401
Royalties	**382**	168	127	**1,258**	226	457
Royalties %	**43%**	31%	39	**38%**	16%	138
Royalties per boe	**18.00**	17.86	1	**17.62**	10.00	76

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, the components of which are subject to different royalty rates, production rates and sales prices.

For the three months ended December 31, 2015, royalties increased 39% from $168,000 in the comparable period in 2014 to $382,000. Royalties as a percentage of revenues increased to 43% for the three months ended December 31, 2015 compared to 31% in the comparable period in 2014. The increased royalty percentage and royalties paid during the current quarter is mainly attributed to higher oil production compared to 2014.

Royalties increased 457% for the year ended December 31, 2015 compared to the same period in 2014 as a result of higher oil and gas production during the year. Royalties as a percentage of revenues increased 138% to 38% as compared to 16% in 2014. This increase is primarily a result of the Pembina 14-5's crown oil royalty rate increasing to a sliding scale maximum of 40% from 5% during Q2 2015, whereas in 2014 production during the first three quarters was subject to the new well royalty rate of 5%. 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 crown 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.

In January of 2016, the Alberta government announced the key highlights of a proposed Modernized Oil & Gas Royalty Framework ("MRF") that comes into effect on January 1, 2017. The Alberta government has not yet released complete details of the MRF; however the changes are not currently expected to have a material effect on the Company's operations. Some highlights of the MRF include;

- No changes to the royalty structure for wells drilled prior to 2017 for a 10-year period from the programs implementation date,
- Harmonized royalties across all hydrocarbons, and reduced royalty rates for mature wells,
- Flat 5% royalty rate on revenues from new conventional wells, with a revenue minus cost framework with a higher post-payout royalty rate based on commodity prices,
- Royalty incentives to encourage cost efficient development of conventional crude oil, liquids and natural gas resources, and
- Neutral internal rate of return for any given play compared to the current royalty framework.

Operating Expenses

	Three Months Ended December 31			Year Ended December 31		
($ thousands except per boe)	**2015**	2014	% Change	**2015**	2014	% Change
Operating expenses	**266**	165	61	**1,185**	330	259
Operating expenses($/boe)	**12.55**	17.50	(28)	**16.60**	14.58	14

Operating expenses were $266,000 or $12.55/boe for the three months ended December 31, 2015 compared to $165,000 or $17.50/boe for the comparable period in 2014 representing an increase of 61% and a decrease of 28% respectively. For the year ended December 31, 2015 operating costs increased by 259% to $1,185,000 or $16.60/boe compared to $330,000 or $14.58/boe compared to 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 45% of total 2015 operating costs.

In late September 2015, the Company and its partners completed facility enhancement work downstream of the Sinopec 13-2 battery to partially reduce blend gas requirements and transportation fees. This new blend facility provides a secondary source of blend gas at no cost to the Company and will reduce production downtime issues and improve treating capacity at the Sinopec 13-2 battery, and has reduced Q4 blend operating costs.

The increase in operating expenses on a per boe basis for the year ended 2015 is a result of a higher oil weighted production mix as the Balsam well production was 38% lower than 2014. The current quarter reduced operating expenses of $12.55/boe as compared to the prior year and current year costs are attributed to lower blend associated costs and prior period fee adjustments recorded during the quarter.

Operating Netbacks

	Three Months Ended December 31			Year Ended December 31		
	2015	2014	% Change	**2015**	2014	% Change
Average sale price:						
Natural gas ($/mcf)	**2.44**	3.55	(31)	**2.53**	4.60	(45)
Oil & NGL ($/bbl)	**46.78**	69.58	(33)	**53.02**	82.01	(35)
Revenues ($/boe)	**42.08**	57.84	(27)	**46.83**	63.16	(26)
Royalties ($/boe)	**(18.00)**	(17.86)	1	**(17.62)**	(10.00)	76
Operating expenses ($/boe)	**(12.55)**	(17.50)	(28)	**(16.60)**	(14.58)	14
Operating netback ($/boe)	**11.53**	22.48	(49)	**12.61**	38.58	(67)

Ironhorse's operating netback per boe for the three months ended December 31, 2015 decreased by 49% from the three months ended December 31, 2014. For the year ended December 31, 2015 operating netback was $12.61/boe compared to $38.58/boe in the same period in 2014 representing a 67% decrease. Realized oil and liquids prices decreased 33% and 35% for the three months and year ended December 31, 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 14% for the year as higher operating costs attributed primarily to the Pembina associated blend gas costs as oil production ramped up over 300% in comparison to 2014. The royalty rate increase is a result of the initial minimum royalty rates for the Pembina wells 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 December 31			Year Ended December 31		
($ thousands except per boe)	**2015**	2014	% Change	**2015**	2014	% Change
G&A expense	**392**	100	292	**688**	473	45
Share-based compensation	**-**	1	(100)	**-**	(1)	(100)
G&A expense ($/boe)	**18.49**	10.60	74	**9.64**	20.91	(54)
Share-based comp ($/boe)	**-**	0.06	(100)	**-**	(0.05)	(100)

G&A expense for the three months ended December 31, 2015 increased 292% to $392,000 from $100,000 for the three months ended December 31, 2015. G&A expenses for the year ended December 31, 2015 increased 45% to $688,000 from $473,000 for the same period in 2014. This increase in both periods is a result of $270,000 in take-over bid costs incurred, offset by a reduction in monthly management fees to $15,000 per month for 2015 as compared with $25,000 per month in 2014 and reduced consulting fees recorded in 2015 that helped to partially offset newly approved director and committee 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 up to $10,000, with the Committee chair receiving up to $15,000. Total director and special committee fees of $57,500 have been included in G&A expense for 2015, $10,000 of which has been paid to a related party who is also a director of Grizzly Resources Ltd.

G&A expense per boe for the three and twelve months ended December 31, 2015 increased 74% to $18.49/boe and decreased 54% to $9.64/boe compared to $10.60/boe and $20.91/boe for the 2014 comparable periods. The substantial variances are due to higher production in 2015 compared to 2014 and the take-over bid costs incurred in Q4 of $270,000 comprising $13/boe of the current quarter G&A expense.

Share-based compensation was $nil for the three and twelve months ended December 31, 2015 compared to $1,000 and a recovery of $1,000 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 2015.

Finance (income) and Expense

	Three Months Ended December 31			Year Ended December 31		
($ thousands except per boe)	**2015**	2014	% Change	**2015**	2014	% Change
Interest (income)	**(4)**	(3)	33	**(16)**	(15)	7
Accretion	**-**	-	-	**3**	2	50
Finance (income)	**(4)**	(3)	33	**(13)**	(13)	-
Finance (income) ($/boe)	**(0.15)**	(0.36)	(57)	**(0.17)**	(0.59)	(71)

For the three months and year ended December 31, 2015 the Company received $4,000 and $16,000 in interest income compared to $3,000 and $15,000 in the comparative 2014 periods. Interest income is dependent on the level of funds held on deposit. During the 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 0.5% and 2%.

Depletion and Amortization

	Three Months Ended December 31			Year Ended December 31		
($ thousands except per boe)	**2015**	2014	% Change	**2015**	2014	% Change
Depletion and amortization	**369**	211	75	**1,475**	473	212
Depletion and amortization ($/boe)	**17.40**	22.38	(22)	**20.66**	20.90	(1)

Depletion and amortization expense was $369,000 or $17.40/boe for the three months ended 2015 as compared to $211,000 or $22.38/boe in the same period in 2014 and $1,475,000 or $20.66/boe for the year ended December 31, 2015 compared to $473,000 or $20.90/boe in same period of 2014. In both cases, the increase in depletion is due to significantly higher production from the Company's Pembina area, offset by less production at Balsam.

Impairment

	Three Months Ended December 31			Year Ended December 31		
($ thousands except per boe)	**2015**	2014	% Change	**2015**	2014	% Change
Impairment	**2,331**	352	562	**6,439**	356	1709
Impairment ($/boe)	**109.90**	37.39	194	**90.18**	15.73	473

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.

For the three months ended December 31, 2015 the Company recognised an impairment charge to its property plant and equipment of $2,331,000 related to its Pembina and Balsam Alberta properties. This was 562% higher than the 2014 comparable period of $352,000.

During the year ended December 31, 2015, the Company recognised $6,439,000 in impairments compared to $356,000 during the same period in 2014. For 2015, Pembina comprised 99% or $6,386,000 of the impairment with the remainder charged to the Company's Balsam area minor CGU which has been fully impaired. The Pembina CGU impairment was triggered primarily by the significant decline in estimated future commodity prices used by the Company's third party external reserve report evaluators and higher than anticipated operating costs 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.

The 2014 impairment charge to property, plant and equipment totalled $356,000 with $307,000 related to Pembina and the remainder to the Company's minor properties. The impairment was the result of the estimated decline in future commodity prices.

Income Taxes

During the fourth quarter of 2015, a deferred income tax recovery of $768,000 was recorded compared to a recovery of $110,000 in the fourth quarter of 2014. For the year to date December 31, 2015, a deferred income tax recovery of $1,970,000 was recorded compared to a recovery of $74,000 for year to date December 31, 2014. The significant deferred tax recovery increase for both the quarter and 2015 year is primarily related to impairment charges recorded in the third and fourth quarters which lowered the book basis of the Company's assets compared to their tax basis.

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. The effect of the income tax rate increase on the Company's 2015 deferred income tax liability was neutralized due to the impact of the impairment charges recorded.

Ironhorse does not expect to pay income tax in Canada in the foreseeable future based on existing tax pools and loss carry forwards. The estimated tax pools at December 31, 2015 and 2014 are as follows:

Estimated Tax Pools:	**December 31,**	December 31,
($ thousands)	**2015**	2014
Canadian development expenditures	**60**	66
Canadian exploration expenditures	**3,195**	3,195
Undepreciated capital costs	**1,648**	2,169
Non-capital losses(1)	**7,654**	7,311
Total	**12,557**	12,741

(1) Non-capital losses carry forward of $7.6 million ($7.3 million in 2014) expire in years 2027 to 2035.

Capital Expenditures

	Three Months Ended December 31			Year Ended December 31		
($ thousands)	**2015**	2014	Change	**2015**	2014	Change
Drilling and completions	**-**	78	(100)	**-**	491	(100)
Facilities, recompletion and workovers	**-**	(66)	(100)	**44**	175	(75)
Capital expenditures	**-**	12	(100)	**44**	666	(93)
Dispositions	**-**	-	-	**-**	-	-
Net	**-**	12	(100)	**44**	666	(93)

Capital expenditures were $nil for the three months ended December 31, 2015 compared to $12,000 for three months ended December 31, 2014 as most of the capital costs were incurred in the first three quarters of 2015. During the year ended December 31, 2015, the Company incurred capital expenditures of $44,000 compared to expenditures of $666,000 for the same period in 2014.

Capital expenditures in 2015 were composed of $20,000 recompletion costs related to the 9-5 and 14-15 Pembina wells and $24,000 of Pembina facility costs to reduce gas blending costs. Capital expenditures for 2014 were composed of $357,000 drilling and abandonment costs for the Pembina 1-8 well, $93,000 of completion costs related to the Pembina 10-5 water injection well and $216,000 of facility and recompletion costs for the Pembina wells and the Pembina 7-5 pad site.

Capital Commitments

The Company anticipates nominal capital spending in 2016 as there are no plans for any further drilling on existing company owned lands. Abandonment expenditures are forecasted to be expended in 2016 at the Company's operated property at Dawson, Alberta, and at Pembina, Alberta, as non-operated partner AFE's for reclamation work on older suspended wells have been approved and work is projected to begin.

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 Company's net working capital is as follows:

As at	**December 31, 2015**	December 31, 2014
Current assets	**4,026**	3,027
Current liabilities	**(1,111)**	(296)
Net working capital	**2,915**	2,731

Shareholders' Equity

As at December 31, 2015, the number of common shares issued and outstanding was 27,885,824 (December 31, 2014 – 27,885,824). As at April 7, 2016, the Company had 27,885,824 common shares and 125,000 stock options issued and outstanding under its stock option plan.

Off Balance Sheet Arrangements

The Company did not have any off-balance sheet arrangements at December 31, 2015 or December 31, 2014.

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 in 2015.

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 year ended December 31, 2015 was $15,000 per month (December 31, 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 13 of the accompanying 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.

Changes in Income Tax Legislation

In the future, income tax laws or other laws may be changed or interpreted in a manner that adversely affects Ironhorse or its shareholders. Tax authorities having jurisdiction over Ironhorse may disagree with how the Company calculates its income for tax purposes.

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 in 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 of development costs.

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 and Alberta governments 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 and 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

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 reduces 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 is replacing 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. IFRS 9 is effective for annual periods beginning on or after 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 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.

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)	Q4 2015	Q3 2015	Q2 2015	Q1 2015	Q4 2014	Q3 2014	Q2 2014	Q1 2014
Volumes								
Natural gas (mcf/d)	202	162	233	171	150	130	112	124
Oil & NGL (bbl/d)	197	189	215	52	77	64	11	8
Total (boe/d)	231	216	254	81	102	86	30	28
Revenues (1)	892	941	1,262	248	545	593	157	134
Funds from operations(2)	(144)	39	401	(68)	123	358	98	(44)
Per share-basic and diluted	(0.01)	-	0.01	-	0.01	0.01	-	-
Net income (loss)	(2,076)	(2,850)	(634)	(159)	(331)	141	51	(82)
Per share-basic and diluted	(0.07)	(0.10)	(0.02)	(0.01)	(0.01)	0.01	-	-
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.

IRONHORSE OIL & GAS INC.

FINANCIAL STATEMENTS

DECEMBER 31, 2015

Kenway Mack Slusarchuk Stewart LLP
Chartered Professional Accountants,
Chartered Accountants

Celebrating 30 years

INDEPENDENT AUDITORS' REPORT

To: The Shareholders of Ironhorse Oil & Gas Inc.

We have audited the accompanying financial statements of Ironhorse Oil & Gas Inc., which comprise the statements of financial position as at December 31, 2015 and 2014, and the statements of comprehensive loss, changes in equity and cash flows for the years then ended and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

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

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

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

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Ironhorse Oil & Gas Inc. as at December 31, 2015 and 2014, and its financial performance and cash flows for the years then ended in accordance with International Financial Reporting Standards.

Kenway Mack Slusarchuk Stewart LLP

Chartered Professional Accountants
Chartered Accountants

April 7, 2016

Calgary, Alberta

IRONHORSE OIL & GAS INC.
Statements of Financial Position
(In thousands of dollars)

As at December 31	2015	2014
ASSETS		
Current assets		
Cash	**3,515**	2,469
Accounts receivable	**203**	278
Prepaid expenses and deposits (note 7)	**308**	280
	4,026	3,027
Property, plant and equipment (note 6)	**10,538**	18,382
Deferred income taxes (note 8)	**642**	-
	15,206	21,409
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**1,111**	296
Decommissioning liabilities (note 7)	**360**	331
Deferred income taxes (note 8)	**-**	1,328
	1,471	1,955
SHAREHOLDERS' EQUITY		
Shareholders' capital (note 9)	**29,875**	29,875
Contributed surplus	**2,048**	2,048
Deficit	**(18,188)**	(12,469)
	13,735	19,454
	15,206	21,409

The accompanying notes are an integral part of these Financial Statements.

Approved on behalf of the Board of Directors:

(signed) "Larry J. Parks"
Director

(signed) "Gerry C. Quinn"
Director

IRONHORSE OIL & GAS INC.
Statements of Comprehensive Loss
(In thousands of dollars except per share amounts)

For the years ended December 31	2015	2014
REVENUES		
Petroleum and natural gas revenues, gross	**3,343**	1,429
Royalties	**(1,258)**	(226)
	2,085	1,203
EXPENSES		
Operating and transportation	**1,185**	330
General and administrative expense (note 16)	**688**	473
Share-based compensation (note 9)	**-**	(1)
Finance costs (note 10)	**(13)**	(13)
Depletion and amortization (note 6)	**1,475**	473
Impairments (notes 6)	**6,439**	356
Gain on disposition of properties (note 6)	**-**	(122)
	9,774	1,496
Loss before income taxes	**(7,689)**	(293)
Income taxes	**-**	2
Deferred income tax recovery (note 8)	**(1,970)**	(74)
Net loss and comprehensive loss	**(5,719)**	(221)
Deficit, beginning of the year	**(12,469)**	(12,248)
Deficit, end of the year	**(18,188)**	(12,469)
Loss per share (note 9)		
Basic and diluted	**(0.21)**	(0.01)

The accompanying notes are an integral part of these Financial Statements.

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

	Shareholders' Capital	Contributed Surplus	Deficit	Total Shareholders' Equity
Balance as at December 31, 2013	29,869	2,051	(12,248)	19,672
Share-based compensation	-	(1)	-	(1)
Share issuance	6	(2)	-	4
Net loss	-	-	(221)	(221)
Balance as at December 31, 2014	**29,875**	**2,048**	**(12,469)**	**19,454**
Net loss	-	-	(5,719)	(5,719)
Balance as at December 31, 2015	**29,875**	**2,048**	**(18,188)**	**(13,735)**

The accompanying notes are an integral part of these Financial Statements.

IRONHORSE OIL & GAS INC.
Statements of Cash Flows
(In thousands of dollars)

For the years ended December 31	2015	2014
Cash flows from operating activities		
Net loss	**(5,719)**	(221)
Items not affecting cash:		
Depletion and amortization (note 6)	**1,475**	473
Impairment of property and equipment (note 6)	**6,439**	356
Accretion of decommissioning liabilities (note 7)	**3**	2
Share-based compensation (note 9)	**-**	(1)
Deferred income tax (recovery) (note 8)	**(1,970)**	(74)
Net change in decommissioning liabilities (note 7)	**-**	(2)
Net change in non-cash working capital (note 14)	**868**	(156)
Net cash flow from operating activities	**1,096**	377
Cash flows from financing activities		
Cash received on the exercise of stock options (note 9)	**-**	4
Net cash flow from financing activities	**-**	4
Cash flows from investing activities		
Property, plant and equipment expenditures (note 6)	**(44)**	(666)
Changes in non-cash working capital (note 14)	**(6)**	(906)
Net cash flow from investing activities	**(50)**	(1,572)
Increase (decrease) in cash	**1,046**	(1,191)
Cash, beginning of the year	**2,469**	3,660
Cash, end of the year	**3,515**	2,469
Supplemental cash information:		
Interest expense paid (received)	**(16)**	(15)
Income taxes paid	**-**	2

The accompanying notes are an integral part of these 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

Statement of Compliance

In these financial statements, unless otherwise indicated, all dollars are expressed in Canadian dollars, with all values rounded to the nearest thousand. The financial statements have been prepared on the historical basis except for financial instruments at fair value through statements of comprehensive loss which are measured at fair value.

These financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). A summary of the Company's significant accounting policies under IFRS is presented in Note 3.

These financial statements were authorized for issuance in accordance with a resolution of the Board of Directors on April 7, 2016.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Revenue Recognition
Revenue associated with the sales of crude oil, natural gas and natural gas liquids ("NGLs") owned by Ironhorse is recognized when the risks and rewards of ownership have been substantially transferred to the customers, the sales price and costs can be measured reliably, and it is probable that the economic benefits will flow to the Company. This is generally met when title passes from the Company to its customer.

Transportation
Costs paid by Ironhorse for the transportation of natural gas, crude oil and NGLs from wellhead to the point of title transfer are recognized when the transportation is provided.

Exploration and Evaluation ("E&E") expense
Costs incurred prior to obtaining the legal right to explore (pre-exploration costs) are expensed in the period in which they are incurred as E&E expense.

Costs incurred after the legal right to explore is obtained, are initially capitalized. If it is determined that the project is not technically feasible or commercially viable or if the Company has decided to discontinue the exploration and evaluation project, the capitalized costs are expensed as E&E expense.

Joint Interests
The Company conducts many of its oil and gas production activities through jointly controlled assets and the financial statements reflect only Ironhorse's proportionate interest in these activities.

Share-based Compensation
In accordance with the Company's stock option plan, stock options may be granted to directors, officers, employees and consultants, all categorized as employees and others providing similar services. The Company follows the fair value method to record the compensation expense for stock options granted under its stock option plan. Under this method, the Company estimates the fair value of stock options using the Black-Scholes option pricing model on the date of grant. Key components of the Black-Scholes model include estimates with respect to share price volatility, a risk free discount rate, option forfeitures and the expected life of the option. The Company recognizes the stock compensation over the vesting period as a share-based compensation expense with a corresponding increase to contributed surplus. When stock options are exercised, the issuance of shares is recorded as an increase to shareholders' capital and a corresponding decrease to contributed surplus.

Assets Held for Sale
Non-current assets are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is met when the sale is highly probable and the asset is available for immediate sale in its present condition.

Non-current assets classified as held for sale are measured at the lower of their carrying amount and fair value less costs to sell, with impairments recognized in the statement of comprehensive loss in the period measured. Non-current assets held for sale are presented in current assets within the balance sheet and are not depleted, depreciated or amortized.

Exploration and Evaluation ("E&E") assets
Exploration and evaluation assets consist of the costs incurred which are pending the determination of technical feasibility and commercial viability of the reserves discovered. E&E assets include undeveloped land, technical services and studies, exploration drilling and testing costs thereon and are capitalized on an area-by-area basis.

Technical feasibility and commercial viability are established when proved and probable reserves are determined to exist. E&E assets are assessed for impairment if (i) sufficient data exists to determine the lack of technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds recoverable amount.

If commercial viability of the reserves is established for the exploration project, the capitalized costs are transferred from E&E asset to development and production assets which are classified as property, plant and equipment ("PP&E") on the balance sheet. Assets are reviewed for impairment at the time they are transferred to PP&E. If an E&E project is determined to be unsuccessful, all associated costs are expensed to the statement of comprehensive loss as E&E expense.

Undeveloped land classified within E&E assets is amortized by major area over the average lease term and recognized in the statement of comprehensive loss. Drilling costs classified as E&E assets are not amortized but are subject to impairment.

Property, Plant and Equipment ("PP&E")
PP&E are stated at cost less accumulated depletion and net impairment expense. PP&E are capitalized on an area-by-area basis and include costs associated with the development and production of petroleum and natural gas assets.

Overhead costs that are directly attributable to bringing an asset to the location and condition necessary for it to be capable of use in the manner intended by management are capitalized. These costs include compensation costs paid to internal technical personnel dedicated to capital projects.

Gains and losses on the dispositions of PP&E are determined by comparing the sale proceeds with the carrying amount of the asset and are recognized separately in the statement of comprehensive loss.

Exchanges of properties are measured at fair value, unless the transaction lacks commercial substance or fair value cannot be reasonably measured. Where the exchange is measured at fair value, a gain or loss is recognized in the statement of operations. When fair value is not used, the carrying amount of the asset given up is used as the cost of the asset acquired.

Depletion, Depreciation and Amortization

Development and production assets within PP&E are componentized into groups of assets ("areas") with similar useful lives for the depletion calculation. Depletion expense is calculated using the unit-of-production method based on:

(a) Total capitalized PP&E costs plus estimated future development costs of proved and probable reserves, including future estimated decommissioning costs;
(b) Relative volumes of petroleum and natural gas production and reserves, before royalties, converted at the energy equivalent conversion ratio of six thousand cubic feet ("mcf") of natural gas to one barrel of oil, and
(c) Total estimated proved and probable reserves calculated in accordance with National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities".

Impairment

Non-financial assets

The Company's development and production assets within PP&E are grouped into cash generating units ("CGU" or "areas") for purposes of assessing impairment. A CGU or area is a grouping of assets that generate cash inflows independently of other assets held by the Company. Geological formation, product type, geography and internal management are key factors considered when grouping the Company's oil and gas assets into areas.

The carrying amount of PP&E is reviewed for indicators of impairment at each reporting date. If any such indicators exist, then the assets recoverable amount is estimated. The recoverable amount is the greater of the area's fair value less cost to sell and the value-in-use. Fair value less costs to sell is estimated using the discounted after-tax future net cash flows. Discounted future net cash flows are based on forecasted commodity prices and costs over the expected economic life of reserves and discounted using market-based rates. Value-in-use is estimated using the discounted present value of the expected future cash flows from continuing use of an area.

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.

E&E assets are assessed for impairment if there is sufficient data that exists to determine technical feasibility and commercial viability of a development area or facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

Financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the fair value or estimated future cash flows of an asset. An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics. All impairment losses are recognized in the statement of comprehensive loss. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in the statement of comprehensive loss.

Decommissioning Liabilities
The Company recognizes decommissioning liabilities for future obligations associated with the retirement of petroleum and natural gas properties. The amount recognized is the net present value of the estimated future expenditures determined in accordance with current requirements and technologies. The decommissioning liability is calculated based on current cost estimates to reclaim and abandon wells and facilities, inflated to the estimated retirement date and then discounted using a risk-free discount rate. The liability is recorded in the period that the obligation is created with a corresponding increase in the carrying value of the related asset. The liability is accreted over time as the effect of discounting unwinds with a corresponding accretion expense recognized in the statement of comprehensive loss within financing costs.

Periodic revision to the liability's specific discount rate, estimated timing of cash flows or to the original estimated undiscounted cost can result in an increase or decrease to decommission liability and the related asset in PP&E. Actual expenditures incurred are recorded against the accumulated liability.

Income Taxes
The Company follows the liability method for accounting for income taxes, where deferred income taxes are recorded for the effect of any temporary difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates expected to apply when the assets are realized or liabilities are settled. Deferred income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment recognized in the statement of comprehensive loss in the period that the change occurs except when it relates to items charged or credited directly to equity, in which case the related deferred income tax effect is also recorded in equity.

Deferred income tax assets and liabilities are offset to the extent there is a legally enforceable right to set off the recognized amounts and the intent is to either settle on a net basis or to realize the asset or settle the liability simultaneously.

Deferred income tax assets and liabilities are presented as non-current.

Flow-through Shares
The Company has financed some of its exploration and development activities through the issuance of common shares on a flow-through basis, pursuant to the terms of a flow-through financing, the tax deductions associated with the resource expenditure are renounced to investors in accordance with income tax legislation. The Company allocates the proceeds received from the flow-through financing between the offering of shares and the sale of a tax benefit. The amount recorded in shareholders' capital is based on the current market price of the shares and the difference is recorded as a current obligation on the statement of financial position. Deferred income tax liability is recognized when the expenditures are incurred and renouncement is probable. The flow-through share obligation is reversed at that time and the difference between the amount of the deferred tax liability and the flow-through share obligation is charged to deferred income tax expense.

Per Share Amounts
Basic and diluted per share amounts are calculated based on the weighted average number of shares outstanding for the period. Common shares issued during the period are included in the weighted average number of common shares from the date the consideration is received by the Company.

The weighted average number of diluted common shares outstanding is calculated using the treasury stock method which assumes that any deemed proceeds received from in-the-money stock options would be used to repurchase common shares at the average market price during the period. Anti-dilutive items are not included in the calculation.

Financial Instruments
Financial Instruments are classified as held for trading, held to maturity, loans and receivables, available for sale, and other liabilities. All of these classifications are measured initially at fair value, with subsequent measurements at amortized cost, except instruments held for trading or available for sale. Amortized cost is calculated using the effective interest rate method.

Changes in the amortized cost are recognized into income through amortization using the effective interest method or when the instrument is impaired or derecognized. Any related transactions costs are recognized into the statement of comprehensive loss in the period incurred.

Financial instruments held for trading are subsequently measured at fair value, with gains and losses recognized in the statement of comprehensive loss in the period they arise.

Financial instruments available for sale are subsequently measured at fair value, with gains and losses arising recorded in comprehensive income. These gains and losses are recognized in comprehensive loss when the instrument is sold, impaired, or derecognized.

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.

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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 11 is effective for annual periods beginning on or after January 1, 2016.

Amendment of IFRS 15 - Revenue Recognition

The IASB has issued IFRS 15 Revenue from contracts with customers which will replace the current revenue guidance on revenue and construction contracts. 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.

4. SIGNIFICANT JUDGMENTS AND ESTIMATES

The preparation of financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and the disclosure of contingencies as at the date of the financial statements. Actual results may differ from these estimates. Significant judgments, estimates and assumptions made by management in the preparation of these financial statements are outlined below.

Judgments

Impairment
Judgments are required to assess when impairment indicators exist and impairment testing is required when determining recoverable amounts of PP&E assets. Judgements used in determining the recoverable amount could affect the carrying value of the related asset.

Exploration and evaluation assets
The accounting policy for exploration and evaluation assets is described in note 3. The application of this policy requires management to make certain estimates and assumptions as to future events and circumstances in assessing whether economic quantities of reserves have been found.

Estimates

Carrying Value of Property, Plant & Equipment
Development and production assets within PP&E are depleted using the unit-of production method based on estimated proved and probable reserves determined using estimated future prices and costs. There are a number of inherent uncertainties associated with estimating reserves. By their nature, these estimates of reserves, including geoscientific interpretation, production forecasts, future commodity prices and costs, and related future cash flows are subject to measurement uncertainty; the impact of changes in these factors on the financial statements of future periods could be material.

Decommissioning liabilities
The calculation of decommissioning liabilities includes management's estimates of future inflation rates, current risk free rates, future restoration and reclamation expenditures and the anticipated timing of those expenditures. The estimated liability and actual costs to be incurred could change significantly due to changes in well production performance, regulations, technology and discount rates applied to determine the net present value of the obligations described in note 7.

Impairment
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 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.

Impairment tests were carried out at December 31, 2015 and were based on value-in-use, using a discount rate of 10 percent to determine the future cash flows from oil and gas reserves and the following commodity price estimates:

	Oil Light Oil at Canadian Light Sweet ($Cdn/barrel)[1]	Gas AECO Spot ($Cdn/mmbtu)[1]
2016	55.20	2.25
2017	69.00	2.95
2018	78.43	3.42
2019	89.41	3.91
2020	91.71	4.20
2021	93.08	4.28
2022	94.48	4.35
2023	95.90	4.43
2024	97.34	4.51
2025	98.80	4.59
Thereafter	+1.5%/year	+1.5%/year

(1) Source: Sproule Associates Ltd. price forecast, effective January 1, 2016

Deferred taxes

The calculation of deferred income taxes is based on a number of assumptions including estimating the future periods in which reversals of temporary differences and tax losses, along with substantively enacted tax rates at the balance sheet date and the likelihood of deferred tax assets being realized.

5. EXPLORATION AND EVALUATION ("E&E") ASSETS

E&E assets consist of the Company's undeveloped land and exploration projects which are pending the determination of proved and probable reserves.

As at December 31, 2015 and 2014 the company did not have E&E assets recorded as the balance of costs were impaired in 2013.

6. 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	44
Changes in decommissioning liabilities	26
Balance, December 31, 2015	23,700

Accumulated depletion and depreciation	
Balance, December 31, 2013	(4.419)
Depletion and depreciation expense	(473)
Impairment	(356)
Balance, December 31, 2014	(5,248)
Depletion and depreciation expense	(1,475)
Impairment	(6,439)
Balance, December 31, 2015	(13,162)

Carrying value	
As at December 31, 2014	18,382
As at December 31, 2015	10,538

During the year ended December 31, 2014 the Company realized its share of a recovery on operating expenses of $117,000 related to its Shackleton property that was sold in a prior year and post-closing adjustments of $5,000 on its Leon Lake Property recording a total gain of $122,000.

The Company did not incur any general and administrative expenses directly attributed to the development of PP&E properties in 2014 and 2015.

Estimated future development costs of $187,200 were included in the calculation of depletion for the period ended December 31, 2015 (2014 - $185,000).

Impairment

For the year ended December 31, 2015, the Company recorded an impairment loss of $6,439,000 against PP&E (2014 - $356,000) of which $6,386,000 related to its Pembina CGU (2014 - $307,000) and $53,000 related to its Balsam and other minor CGUs (2014 - $49,000).

The impairment loss in 2015 related to the Company's main CGU at Pembina was due to a decrease in the value-in-use triggered primarily by the significant decline in the forward commodity prices for oil, natural gas and liquids at December 31, 2015 as compared to December 31, 2014, as prepared by the Company's external reserve evaluators.

The recoverable amount for the Pembina CGU is $10.5 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% (2014 – 10%). For the purposes of the impairment calculation the Company made a judgement that the production of the Pembina CGU is expected to resume in 2016 (note 15).

7. DECOMMISSIONING LIABILITIES

Years ended December 31	**2015**	2014
Balance, beginning of year	**331**	322
Change in estimates and discount rate	**26**	9
Settlement of decommissioning liabilities	**-**	(2)
Accretion expense	**3**	2
Balance, end of year	**360**	331

Ironhorse's decommissioning liabilities result from the net ownership interests in petroleum and natural gas assets including well sites, gathering systems and production equipment. The total undiscounted amount to settle the Company's decommissioning liabilities is estimated at $0.4 million (2014 - $0.4 million). Over the next 2-3 years approximately $155,000 of these costs are expected to be incurred with the remainder expected to be incurred between 2020 and 2033. A risk-free rate of 0.5-2% (2014 – 1-3%) and an inflation rate of 2% (2014 – 2%) were used to calculate the present value of the decommissioning liabilities.

In compliance with the Alberta Energy Regulator's licensee liability rating program, the Company was required to pay security deposits of $32,000 in 2015 and $255,000 during 2014. The deposits are related to the Company's sole operated property at Dawson, Alberta where the wells were suspended in 2013.

8. INCOME TAXES

The following table reconciles income taxes calculated at the Canadian statutory rate:

	December 31, 2015	December 31, 2014
Loss before income taxes	**(7,689)**	(293)
Canadian statutory tax rate [1]	**26.0%**	25.0%
Expected income tax recovery	**(1,999)**	(73)
Effect of taxes resulting from:		
Effect of change in tax rates	**29**	-
Change in estimated pool balances	**-**	(1)
Deferred income tax recovery	**(1,970)**	(74)

[1]The statutory rate consists of the combined tax rate for the Company for the year ended December 31, 2015. The general combined federal and provincial tax rate increased from 25% in 2014 to 27% in 2015 as the Alberta government raised the provincial tax rate from 10% to 12% effective July 1, 2015.

The net deferred income tax asset (liability) is comprised of the following:

	December 31, 2015	December 31, 2014
Deferred income tax liabilities:		
Petroleum and natural gas properties	**(1,522)**	(3,238)
Deferred income tax assets:		
Decommissioning liabilities	**97**	82
Non-capital losses	**2,067**	1,828
Deferred income tax asset (liability)	**642**	(1,328)

Estimated tax pools	**December 31, 2015**	December 31, 2014
Canadian development expenditures	**60**	66
Canadian exploration expenditures	**3,195**	3,195
Undepreciated capital costs	**1,648**	2,169
Non-capital losses[1]	**7,654**	7,311
Total	**12,557**	12,741

[1]Non-capital losses carryforward of $7.6 million ($7.3 million in 2014) expire in years 2027 to 2035.

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. The effect of the income tax rate increase on the Company's 2015 deferred income tax liability was neutralized due to the impact of the impairment charges recorded during the year.

Although the Company has incurred losses for the past two years, a net deferred tax asset of $642,000 has been recorded in 2015. The Company recognized a net deferred tax asset for non-capital loss carry-forwards based on the Company's estimate that it is probable that it will earn sufficient taxable profits in the future to utilize these losses before they expire. Future taxable profits were estimated using the independently evaluated reserve report.

9. SHAREHOLDERS' CAPITAL

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

	Number of of shares	Amount
Balance, December 31, 2013	**27,860,824**	**29,869**
Issued on exercise of options	25,000	4
Transfer from contributed surplus on exercise of options	-	2
Balance, December 31, 2014 and 2015	**27,885,824**	**29,875**

Stock Options and Share-Based Compensation

The Company has a stock option plan under terms of which it will grant options to acquire common shares to certain officers, directors, employees and consultants, which vest equally over the first, second, and third anniversary of their grant date and have a maximum term of five years. Under terms of the plan, options totaling up to 10% of the common shares outstanding from time to time are issuable, and no more than 5% of the outstanding options may be issued to any one person as defined by the plan.

During the year ended December 31, 2014, 25,000 options were exercised at a price of $0.17 per option.

The following tables summarize information about the Company's stock options outstanding:

	Number of options	Weighted average Exercise price
Balance, December 31, 2013	**1,186,000**	**0.70**
Exercised	(25,000)	0.17
Forfeited or expired	(420,000)	1.03
Balance, December 31, 2014	**741,000**	**0.53**
Forfeited or expired	(616,000)	0.60
Balance, December 31, 2015	**125,000**	**0.17**

Exercise Price	Options Outstanding	Options Vested	2015 Remaining Contractual Life (Years)	Options Outstanding	Options Vested	2014 Remaining Contractual Life (Years)
0.15 – 0.50	**125,000**	**125,000**	**1.07**	555,000	493,334	1.28
0.51 – 1.50	**-**	**-**	**-**	186,000	186,000	0.17
	125,000	**125,000**	**1.07**	741,000	679,334	1.00

The share-based compensation expense is calculated based on the fair value of the stock options granted during the year using the Black-Scholes pricing model. In 2014 and 2015, no options were granted.

Weighted average number of shares

Per share amounts	**2015**	2014
Weighted average common shares – basic	**27,885,824**	27,885,824
Weighted average common shares – diluted	**27,885,824**	27,885,824

For the year ended December 31, 2015 the stock options outstanding were anti-dilutive and were not included in the diluted common shares calculation.

10. FINANCE COSTS

Years ended December 31	**2015**	2014
Interest expense (income), net and finance charges	**(16)**	(15)
Accretion and decommissioning liabilities (note 7)	**3**	2
	(13)	(13)

11. CAPITAL MANAGEMENT

Ironhorse's capital structure includes shareholders' equity, and working capital, with no bank debt.

The Company's objective is to maintain a strong capital structure that will allow it to execute on any potential investment opportunities that may arise depending on market conditions.

The methods used by the Company to monitor capital are based on the ratio of net debt to annualized funds from operations and the ratio of net debt to the maximum amount of the Company's credit facility when applicable.

As at December 31, 2015, Ironhorse had no bank debt or bank facility and positive working capital of $2.9 million as a result of selling certain producing properties and repaying all outstanding bank debt in 2013.

The Company's shareholders' capital is not subject to external restrictions. The Company's working capital is calculated as follows:

	December 31, 2015	December 31, 2014
Current assets	**4,026**	3,027
Current liabilities	**(1,111)**	(296)
Working capital	**2,915**	2,731

12. FINANCIAL INSTRUMENTS

(A) Fair Value of Financial Assets and Liabilities

The fair values of cash, accounts receivable and accounts payable and accrued liabilities approximate their carrying amounts due to the short-term maturity of those instruments.

Fair value measurement of assets and liabilities recognized on the statement of financial position are categorized into levels within a fair value hierarchy based on the nature of valuation inputs. The fair value hierarchy has the following levels:

Level 1 Quoted prices in active markets for identical assets or liabilities;
Level 2 Inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly;
Level 3 Inputs for asset or liabilities that are not based on observable market data.

Cash is classified as Level 1.

(B) Risks Associated with Financial Assets and Liabilities

Commodity price risk

The Company produces oil and natural gas which have historically been subject to fluctuations in price. The Company's production is mainly oil weighted averaging 230 barrels of oil equivalent per day during Q4. An increase of C$5 per barrel in the price of oil would increase quarterly cash flows available to the Company by approximately $47,000. A similar decrease in commodity prices would have the opposite impact.

Credit risk
Credit risk is the potential financial loss to the Company if a customer or joint venture partner is unable to meet its contractual obligations and arises principally from the Company's accounts receivable with respect to the sale of oil and natural gas. The Company's oil and natural gas is marketed on behalf of the Company by a related party under standard industry terms. In order to mitigate credit risk, oil and natural gas is marketed to various established credit worthy purchasers. The amounts are typically remitted to the Company by the 25th day of the month following production. Joint interest receivables are typically collected within one to three months following production.

At December 31, 2015 accounts receivable were $203,000 of which: $182,000 relates to the Company's Pembina area property net revenues, with the remaining balance receivable from joint venture partners. Approximately 99% of the outstanding accounts receivable were settled in Q1 2016.

The Company's allowance for doubtful accounts was nil as at December 31, 2015 and 2014. The Company did not record any additional provision for non-collectible accounts receivable during the years ended December 31, 2015 and 2014.

Liquidity risk
Liquidity risk is the potential for the Company to have difficulty in meeting its obligations associated with financial liabilities as they become due. Ironhorse's financial liabilities consist of accounts payable and accrued liabilities. All of the Company's financial liabilities have contractual maturities of less than one year and accounts payable are processed within normal payment terms.

Ironhorse prepares an annual budget which is monitored and updated throughout the year. Occasionally the Company enters into fixed price contracts with respect to the sale of a portion of its production to protect its cash flow from commodity price declines.

The Company's approach to managing liquidity risk is to meet its obligations when due through its available cash resources and seek potential credit facilities in the future. Budgets and forecasts are prepared based on reasonable assumptions about production, pricing, royalty structure and estimated future capital expenditures. These assumptions are updated on a regular basis. The budgets and forecasts are reviewed on an ongoing basis in order to identify future cash and financing requirements.

Interest rate risk
The Company does not have an operating facility at December 31, 2015.

Foreign exchange rate risk
The Company is exposed to the risk of changes in the Canadian/U.S. dollar exchange rate on sales of commodities that are denominated in U.S. dollars or directly influenced by U.S. dollar benchmark prices. As of December 31, 2015 Ironhorse had no accounts receivable or accounts payable denominated in foreign currencies.

13. RELATED PARTY 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.

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 year ended December 31, 2015 was $15,000 per month (2014 - $25,000 per month) as the fee was reduced effective Jan 1, 2015. The management agreement is reviewed annually to account for any changes in the Company's operating assets.

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

For the years ended December 31,	**2015**	2014
Capital expenditures	**20**	657
Operating expenses	**925**	114
Petroleum and natural gas revenues	**3,276**	1,209
Proceeds on sale	**-**	6
General and Administrative – Management Fees	**180**	300

The inter-company net receivable (payable) balances due from (to) related parties were as follows:

As at December 31	**2015**	2014
Grizzly Resources Ltd.	**(449)**	195
Copper Island Resources Ltd.	**(3)**	-

The amounts outstanding at December 31, 2015 were settled in Q1 2016.

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. Total director fees of $57,500 were paid during 2015, with $10,000 of that total paid to a member of the Board of Directors who is also a director of Grizzly Resources Ltd.

Key Management and Personnel

Key management personnel of the Company consist of its directors, officers and the management and consultants of GRL that provide the monthly management services described above. Additionally share-based awards may be awarded to employees and consultants of GRL for providing management services to Ironhorse.

14. SUPPLEMENTAL DISCLOSURES

For the years ended December 31	**2015**	2014
Changes in non-cash working capital:		
Accounts receivable	**75**	257
Prepaid expenses and deposits	**(28)**	(235)
Accounts payable and accrued liabilities	**815**	(1,084)
	862	(1,062)
Relating to:		
Operating activities	**868**	(156)
Investing activities	**(6)**	(906)
	862	(1,062)

15. SUBSEQUENT EVENTS

Shut-in production

Subsequent to December 31, 2015, the Company announced that on January 19, 2016 the operator of the Pembina area temporarily shut-in production from the Nisku L2L Pool (the "Pool"), the Company's main source of cash flow, until commodity prices recover as the wells are uneconomic in the current commodity price environment.

Lawsuit – Statement of Claim Filed

Subsequent to December 31, 2015, on February 23, 2016, the Company and GRL jointly filed a Statement of Claim in the Court of Queen's Bench of Alberta against Sinopec Daylight Energy Ltd. ("Sinopec"), the operator of pipelines and facilities associated with the Pool production. The Company and GRL are seeking damages against Sinopec for misrepresentation and breach of contract.

16. UNSOLICATED TAKE-OVER BID

Shareholders of the Company received an unsolicited all cash take-over bid offer (the "Offer") to acquire the outstanding shares of Ironhorse by 1927297 Alberta Ltd. (the "Offeror"), a corporation wholly-owned by Timmerman Trust, commencing on November 4, 2015 at $0.17 per share.

On February 5, 2016 the Offer expired as the minimum tender condition of the Offer was not met and the Offeror is not taking up any shares deposited under the Offer.

Ironhorse has incurred approximately $270,000 in general and administrative costs during the fourth quarter of 2015 in defense of the take-over bid.