IRONHORSE

OIL & GAS INC.

Annual Report
2006

HIGHLIGHTS			
Year ended December 31,	**2006**	**2006 vs. 2005**	2005
Production:			
Gas (thousand cubic feet per day)	**1,162**	**+1,537%**	71
Oil and NGLs (barrels per day)	**8.2**	**-23%**	10.7
Boe (barrels oil equivalent per day)	**201.9**	**+794%**	22.6
Revenue ($)	**2,709,734**	**+449%**	493,616
Funds flow from operations ($)	**1,049,728**	**+442%**	193,753
Net income ($)	**(732,821)**	**-318%**	335,476
Per diluted share amounts:			
Funds flow from operations ($/share)	**$0.06**	**+200%**	$0.02
Net income ($/share)	**$(0.04)**	**-233%**	$0.03
Number of shares outstanding:			
Basic weighted average	**16,346,171**	**+37%**	11,912,654
Diluted weighted average	**16,346,171**	**+30%**	12,556,186
End of Period	**17,067,392**	**+15%**	14,871,558

Ironhorse Oil & Gas Inc. is uniquely positioned as an emerging petroleum and natural gas company with significant multi-year development projects offering continued year-over-year production growth. The Company's primary goal is to increase net asset value per share through disciplined capital investment and the pursuit of strategic initiatives that optimize the Company's asset base and position in the oil and gas marketplace.

MANAGEMENT DISCUSSION AND ANALYSIS

Management discussion and analysis of the financial condition and results of operations of the Company should be read in conjunction with the Company's audited financial statements and related notes for the year ended December 31, 2006, and the year ended December 31, 2005. Additional information about the Company, its operations and history including the Company's Annual Information Form may be found as filed on the System for Electronic Data Analysis and Retrieval at www.sedar.com. The calculation of barrels of oil equivalent ("boe") is based on a relative energy content conversion ratio of six thousand cubic feet ("mcf") of natural gas to one barrel of oil. Production volumes reported are the Company's interest before royalties. All amounts are expressed in Canadian dollars unless otherwise stated.

This discussion and analysis may contain forward-looking information that is subject to known and unknown risks, uncertainties and other factors. Readers are cautioned that actual future results, performance or achievements may be different from those expressed or implied and the difference may be material.

Non-GAAP Measures

The financial data presented has been prepared in accordance with Canadian generally accepted accounting principles (GAAP) except for the term “funds flow from operations”. Funds flow from operations has been presented for information purposes only and should not be considered an alternative to, or more meaningful than cash flow from operating activities as determined in accordance with GAAP. The determination of the Company’s funds flow from operations may not be comparable to the same reported by other companies. Funds flow from operations refers to net income from the statement of operations plus non-cash expenses, less abandonment costs incurred and excludes the change in non-cash operating working capital for the period. Funds flow from operations per share was calculated using the same weighted average shares outstanding used in calculating net income per share.

Disclosure Controls and Internal Controls for Financial Reporting

The Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of the Company’s disclosure controls and procedures and concluded that these disclosure controls and procedures were effective as of December 31, 2006 and in respect of the year then ended.

The Chief Executive Officer and Chief Financial Officer concluded that the design of internal control over financial reporting was effective as at December 31, 2006 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. As the Company has limited segregation of duties, it relies on key individuals as an integral part of this control process.

Business Environment and Risks

In addition to being impacted by operational risks normally associated with oil and gas operations, the Company is directly affected by commodity price fluctuations, particularly on sales volumes that the Company has not hedged. World and Canadian crude oil prices increased somewhat in 2006 versus 2005 levels. Canadian natural gas prices in 2006 decreased significantly from 2005 levels.

	Q4 ’06	Q3 ’06	Q2 ’06	Q1 ’06	Q4 ’05	Q3 ’05	Q2 ’05	Q1 ’05
West Texas Intermediate for crude oil (US$/bbl)	$57.75	$70.66	$70.67	$63.26	$60.14	$63.18	$53.18	$49.44
Edmonton posted reference for crude oil (C$/bbl)	65.07	79.23	78.34	68.91	71.74	76.81	66.09	61.58
AECO-C for natural gas (C$/mcf)	6.91	5.71	6.07	7.53	11.68	9.38	7.37	6.90

The Company considers the risks of oil and natural gas price fluctuations and the Company’s requirements to maintain cash flow to pursue capital investment opportunities. In the year ended December 31, 2006, the Company entered into a collar contract for the sale of a portion of its natural gas production. The contract term commenced November 1, 2006 and extended to March 31, 2007 and provided for a ceiling of $11.10 and a floor of $8.00 per gigajoule (GJ) on 625 GJ per day during the contract term. This volume approximates to 40% of the Company’s fourth quarter production. Market sales prices in November and December of the year were lower than the contract floor. As a result, the Company earned $36,318 from the contract during those months. The value of the remaining term of the contract, as measured at the end of the year, was approximately $90,000. The contract was costless to the Company.

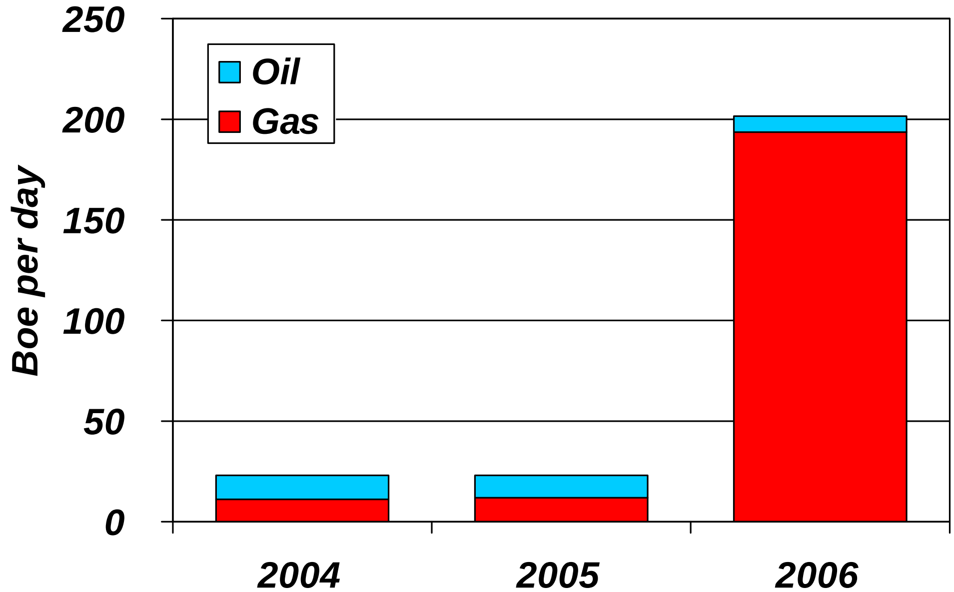
Subsequent to the year-end and coincident to the termination of the contract described above, the Company has entered into an additional collar contract for the sale of 1,000 GJ per day throughout the period of April 1, 2007 to March 31, 2008. This contract provides for a ceiling of $9.42 and a floor of $7.00 per GJ during the contract term.

Operations

The Company has been a petroleum and natural gas producer since 2003. In the second quarter of 2006, the Company began producing natural gas from a new field in Southwest Saskatchewan, where the Company has a 50% working interest in both the producing wells and related infrastructure. The Company began producing from seven wells at that time. Production from this area has and will continue to significantly increase the Company's overall production rate year-over-year.

Subsequent to the year-end, the Company drilled an additional 31 wells in the Southwest Saskatchewan field and brought 25 of these wells on production by the end of the first quarter of 2007. Five of the remaining six wells were not fully completed due to an early break-up in the area. The sixth well was drilled in a portion of the field that is dependent on a pipeline installation currently scheduled for the fall of 2007. All six wells from this program are scheduled to be fully producing by the first quarter of 2008.

PRODUCTION OPERATIONS



Production for the year, on average, was 202 boe per day. At the beginning of the year and continuously until the production from the Company's Southwest Saskatchewan field commenced in May of 2006, the Company produced an average of 20 boe per day. Following the production additions at Southwest Saskatchewan, the Company's production for the balance of the year was 318 boe per day.

Selected Annual Operating Data			
Year ended December 31,	**2006**	2005	2004
Crude oil and natural gas liquids production (barrels)	**3,002**	3,921	4,304
Natural gas production (mcf)	**424,091**	25,907	24,941
Barrels of oil equivalent (boe)	**73,684**	8,239	8,461
Per day (boe per day)	**202**	23	23
Price per barrel ($/barrel)	**$66.18**	$62.72	$49.42
Price per mcf ($/mcf)	**$5.92**	9.56	7.09
Price per boe ($/boe)	**$36.78**	59.91	46.04
Royalty rate	**40.3%**	24.8%	23.8%
Operating costs per boe	**$4.30**	$10.79	$7.32
General and admin per boe	**$3.91**	16.85	12.90
Revenue	**$2,709,734**	$493,616	$389,524
Operating netback	**1,300,631**	282,252	234,905
Funds flow from operations	**1,049,728**	193,753	130,281
Net income (loss)	**(732,821)**	335,476	3,684
Basic and diluted net income (loss) per share	**(0.04)**	0.03	–
Basic weighted average shares	**16,346,171**	11,912,654	8,871,558
Diluted weighted average shares	**16,346,171**	12,556,186	8,939,742
Total assets as at period end	**$16,848,830**	$7,524,256	$768,630

In 2006, as compared to 2005, the price received by the Company from natural gas sales dropped 38%, of which 9% is attributed to an overall reduction in natural gas quality and 29% is attributed to a reduction in natural gas markets. Warmer weather during winter periods in the high population centres in the United States, coupled with higher natural gas supplies resulting from an aggressive drilling program from industry and an uneventful hurricane season versus expectations contributed to this downward pressure on natural gas prices. In spite of the Company experiencing this reduction in the average sales prices received, production increases of 794% over 2005 volumes resulted in a year-over-year revenue increase of 449% and a record high of $2,709,734 in sales for the Company. All of these incremental volumes were produced at the Company's Southwest Saskatchewan field.

As a result of the improved production, the operating netback (revenue less royalties and operating costs) for 2006 amounted to $1,300,631 from its properties for the year, a 361% increase over 2005. This operating netback provided a source of capital for re-investment and reduced the requirement for equity and debt advances to complete the Company's drilling program.

In 2006, at Southwest Saskatchewan, the Company was subject to overriding royalties of 17% on the revenue generated from the field. Crown and crown-equivalent royalties, as a percentage of sales revenue decreased in 2006 versus 2005 due to reduced prices realized in the year versus the prior year and partially offset the impact of the overriding royalties on the Company. The royalty rate for the Company increased by 15.5% overall. Subsequent to the year-end, the Company acquired the 2% overriding royalty on the Southwest Saskatchewan field previously held by one of the Company's board members, reducing the overriding royalty impact on the Company in future periods. In the fourth quarter of 2006, as a result of amounts earned on the Company's natural gas collar contract which do not attract any royalty, the average royalty rate for that quarter was lower.

In Southwest Saskatchewan, now the Company's most significant producing asset, the Company owns a 50% working interest in the area infrastructure. This results in an ability to operate at a low cost per unit of production. As a result, the average operating cost per boe in 2006 was cut by 60% from 2005 levels to $4.30. In 2005, the Company owned none of its infrastructure and paid third parties to handle its production.

Operations (continued)

The increased production also reduced the Company's general and administration costs per boe by 77% from 2005 levels. The Company is benefiting from improved economies of scale in its administration due to the increased production.

Although overall operating metrics, with the exception of price per unit of production, improved in 2006 versus 2005, non-cash charges relating to depletion and amortization and, to a lesser extent, stock based compensation increased significantly. These charges resulted in Company recording a loss for the 2006 year.

Depletion and amortization increased by over 3,000% over 2005 levels and by approximately 250% per unit of production, to $19.82 per boe. This increase is due to the higher capital costs included in the depletion base from Southwest Saskatchewan and Pembina for 2006 versus only the Company's minor properties for 2005. The schedule of development dictates a significant infrastructure component prior to the drilling of wells in the area. As a result, finding and development and depletion rates at Southwest Saskatchewan are expected to be higher for the Company in its early stages and are expected to reduce in future periods.

As the Southwest Saskatchewan field continues to develop, production is expected to continue to grow. In addition, management expects improvements in natural gas prices in future periods as compared to 2006 levels. The combination of these events is expected to significantly improve the Company's overall profitability.

Selected Quarterly Operating Data

	Q4 '06	Q3 '06	Q2 '06	Q1 '06	Q4 '05	Q3 '05	Q2 '05	Q1 '05
Crude oil and natural gas liquids production (barrels)	681	717	787	817	922	969	1,024	1,006
Natural gas production (mcf)	129,664	177,677	110,880	5,870	6,272	6,460	6,630	6,545
Barrels of oil equivalent (boe)	22,292	30,330	19,267	1,795	1,967	2,046	2,129	2,097
Per day (boe per day)	242	330	212	20	21	22	23	23
Price per barrel ($/barrel)	$58.46	$73.52	$73.38	$59.23	$62.14	$69.36	$62.25	$57.32
Price per mcf ($/mcf)	7.22	5.25	5.31	9.03	12.79	9.86	8.23	7.53
Price per boe ($/boe)	43.78	32.49	33.58	56.48	69.89	63.98	55.56	51.00
Royalty rate	36.9%	43.4%	43.5%	23.2%	23.3%	23.3%	26.3%	27.0%
Operating costs per boe	$4.14	$4.06	$3.94	$14.21	$12.39	$13.98	$9.43	$7.54
General and admin per boe	5.55	1.65	4.97	10.61	35.27	9.14	15.70	8.25
Interest per boe	0.52	–	–	–	–	–	–	–
Revenue	$975,898	$985,517	$646,935	$101,384	$137,480	$130,896	$118,293	$106,947
Operating netback	523,475	435,233	289,586	52,337	81,112	71,757	67,133	62,250
Funds flow from operations	388,414	394,680	210,953	55,681	38,535	78,614	36,403	46,767
Net income (loss)	(208,302)	(277,688)	(150,176)	(96,655)	291,045	4,841	14,325	25,265
Basic and diluted net income (loss) per share	(0.01)	(0.01)	(0.01)	(0.01)	0.02	–	–	–
Basic weighted avg. shares (000s)	17,065	17,053	16,350	14,885	14,872	14,872	8,937	8,872
Diluted weighted avg. shares (000s)	17,065	17,053	16,350	14,885	15,723	15,709	9,430	9,017
Total assets as at period end (000s)	16,849	14,664	15,804	14,906	7,524	7,339	7,181	835

General and Administration and Interest Expense

General and administration costs per boe increased in the fourth quarter to $5.55 from the Company's third quarter rate of $1.65 due to year-end professional fees and fees related to the negotiation of its debt facility with a financial institution that were incurred in the fourth quarter. General and administration charges, in aggregate, increased to $288,466 in 2006 from $138,823 in 2005. The most significant portion of this increase was in the production-based portion of the services fee paid to Grizzly Resources Ltd., a company related by virtue of common management. Under a services agreement, the Company pays a charge based on a fee per unit of production and a percentage of capital expenditures. The portion related to capital expenditures is capitalized. The fee per unit of production increased due to the increase in the Company's overall production in 2006 versus 2005.

Stock-based compensation charges are amortized over stock option vesting periods. In 2006, stock based compensation charges rose due to stock options granted in 2006 plus the amortization of previous grants that are being amortized over vesting periods. The charges relating to stock-based compensation are expected to decrease in future periods as past options become vested.

In 2006, the Company negotiated an increase in its revolving production loan facility with a financial institution. The Company may borrow up to $6,000,000 under this facility. As at December 31, 2006, the Company had borrowed $1,806,000. The Company's first drawings on this facility occurred in the fourth quarter of 2006. The Company incurred $11,516 in interest costs during 2006 versus $ nil in 2005.

Depletion and Amortization

($)	**Q4 '06**	**Q3 '06**	**Q2 '06**	**Q1 '06**	**Q4 '05**	**Q3 '05**	**Q2 '05**	**Q1 '05**
Depletion	537,872	683,264	221,724	7,597	8,240	10,836	11,410	11,237
Asset retirement expense	1,112	2,854	2,906	3,081	1,759	1,764	(707)	2,224
Depletion per boe	24.13	22.53	11.51	4.23	4.19	5.30	5.36	5.36

The Company's depletion rate increased in 2006 to $19.82 per boe from $5.64 per boe in 2005 due to the additional capital costs charged in Southwest Saskatchewan and Pembina per proven reserves added. In 2005, the Company depleted only the costs of its minor properties. In Southwest Saskatchewan, capital costs charged per unit of proven reserve additions are expected to decline as the project develops. Charges for expenditures at the first stage in Pembina have been included in the property and equipment costs subject to depletion with no proven reserves recorded in the area to date. Management considers the Pembina area to be highly prospective and expects that future reserve additions in the area will reduce future depletion rates for the Company.

Capital Expenditures

($000s)	**Q4 '06**	**Q3 '06**	**Q2 '06**	**Q1 '06**	**Q4 '05**	**Q3 '05**	**Q2 '05**	**Q1 '05**
Southwest Saskatchewan								
Land	59	45	39	2,165	–	–	–	–
Drilling	729	120	88	2,198	–	–	–	–
Facilities	2,606	36	896	4,207	–	–	–	–
Pembina								
Land	1	–	–	82	–	104	2,527	–
Seismic	–	–	–	91	–	–	–	–
Drilling	4	38	124	385	701	102	–	–
Minor Areas								
Drilling	1	–	–	–	–	–	–	–
Facilities	–	–	–	–	–	–	1	–
Total	3,400	239	1,147	9,128	701	206	2,528	–

Capital Expenditures (continued)

The Company commenced its first capital expenditure program in the second quarter of 2005 when it acquired a significant land position in the prolific Pembina Nisku trend from Grizzly Resources Ltd., a related company by virtue of common management. Licensing of wells, due to heightened regulation related to wells with significant hydrogen sulfide content and for drilling locations within close proximity to towns and villages, has been delayed significantly in the area. The Company's locations fall into both of these categories. Taking advantage of unutilized cash resources, the Company commenced capital operations in Southwest Saskatchewan in the first quarter of 2006 where it obtained a 50% working interest in 6,560 acres. The Company constructed facilities in the area and brought seven wells on production in the second quarter of 2006.

In Southwest Saskatchewan, the Company has negotiated land acquisitions that are expected to occur in five stages. The Company has a 50% working interest in each stage. The first stage was completed in January 2006 represented 6,560 acres. The second and third stages, together representing 5,160 acres, were completed in January and March of 2007. The fourth and fifth stages, together representing 5,880 additional acres, are anticipated to be complete in 2007 and 2008 respectively.

Subsequent to the year-end, the Company drilled an additional 31 wells and brought 25 of these wells on production by the end of the first quarter of 2007. The remaining six wells are scheduled to be brought on production in the first quarter of 2008. As a result, the Company's production in 2007 is anticipated to significantly increase over 2006 levels. In addition, the completion of the third stage of land acquisition provides the Company with a further 36 drill-ready locations. The anticipated completion of the fourth and fifth stages of land acquisition is expected to further increase the number of drilling locations.

The wells drilled to date, at Southwest Saskatchewan, have been 100% commercially successful in discovering natural gas. The area is surrounded by producing wells and management expects continued success throughout its drilling plans over the next two years. Grizzly Resources Ltd. is the operator for the area.

At Pembina, the Company has obtained one license, where the Company has a 7% working interest, and is in the process of licensing four further locations where the Company has an 18.75% working interest. Significant lead time is required to obtain licenses on several of the selected locations. Several discoveries in this area have yielded production in excess of 1,000 boe per day per well.

Subsequent to the year-end, the Company expanded into Northeast British Columbia where the Company drilled one well in the first quarter of 2007. The well was evaluated as non-commercial and was abandoned. The Company's presence here has provided an additional opportunity in the area. The new opportunity is unique from the well drilled and the Company is evaluating 2D proprietary seismic data that the Company recently shot to determine whether the opportunity is prospective for natural gas developments.

Petroleum and Natural Gas Reserves

	Year Ended December 31, 2006			Year Ended December 31, 2005		
	Oil & Liquids	Natural Gas	Barrels Equivalent	Oil & Liquids	Natural Gas	Barrels Equivalent
Proven reserves	(mbbls)	(mmcf)	(mboe)	(mbbls)	(mmcf)	(mboe)
Opening balance	28	243	69	30	191	62
Production	(3)	(424)	(74)	(4)	(26)	(8)
Revisions	(4)	10	(2)	2	78	15
Discoveries and extensions	–	5,690	948	–	–	–
Closing balance	21	5,519	941	28	243	69
Probable reserves						
Opening balance	4	40	11	7	54	16
Revisions	2	8	3	(3)	(14)	(6)
Discoveries and extensions	–	1,815	303	–	–	–
Closing balance	6	1,863	317	4	40	10
Proven plus probable reserves						
Opening balance	32	283	79	37	245	78
Production	(3)	(424)	(74)	(4)	(26)	(8)
Revisions	(2)	18	1	(1)	64	9
Discoveries and extensions	–	7,506	1,251	–	–	–
Closing balance	27	7,382	1,257	32	283	79

During the year, the Company discovered 7.5 billion cubic feet, net to the Company, of proven plus probable natural gas reserves at Southwest Saskatchewan. At December 31, 2006, the Company had incurred costs of $13.2 million, of which $3.0 million relate to lands where no reserves have yet been assigned. Future capital expenditures on lands, to which reserves have been assigned, are estimated at $7.7 million. As a result, the Company's finding and development costs for the Southwest Saskatchewan area are approximately $2.40 per mcf or $14.30 per boe of proven plus probable reserves. The Company's finding costs for 2006 overall are approximately $16.50 per boe of proven and probable reserves include the first phase of the Pembina area land and drilling costs where no reserves have yet been added.

Reserve estimates reflect only the Company's interests in its producing operating areas. No amounts are included in this report for the Company's interests at Pembina or for the second and third stage of acquired acreage in Southwest Saskatchewan that was acquired subsequent to the year-end. Both 2006 and 2005 year-end evaluations were performed by GLJ Petroleum Consultants.

Present Value Continuity of Petroleum and Natural Gas Reserves

The Company's estimates of future cash flows were significantly impacted by the additions at Southwest Saskatchewan.

The value of the Company's petroleum and natural gas reserve estimates from the Company's external reserve evaluation performed by GLJ Petroleum Consultants, effective December 31, 2006 and as measured by the estimates of future cash flows from proved plus probable reserves and discounted by 10%, was measured at $11,861,000, up from $1,095,000 at December 31, 2005. The most significant cause of the change in the year was $12,069,000 relating to discoveries and extensions, all from the Southwest Saskatchewan field. Cash flow of $1,143,000 was derived from the seven wells that produced at Southwest Saskatchewan and $157,000 was earned from the Company's minor areas.

	Year ended December 31, 2006		Year Ended December 31, 2005	
	PV 0%	PV 10%	PV 0%	PV 10%
Proven reserves	**($000s)**	**($000s)**	**($000s)**	**($000s)**
Opening balance	1,450	1,028	1,206	815
Cash flow	(1,301)	(1,301)	(282)	(282)
Changes in present value	–	103	–	82
Price revisions	54	(75)	150	136
Discoveries and extensions	13,938	8,949	–	–
Technical revisions	(36)	(75)	376	277
Closing balance	14,105	8,629	1,450	1,028
Probable reserves				
Opening balance	205	67	353	131
Changes in present value	–	7	–	13
Price revisions	67	(13)	(69)	(13)
Discoveries and extensions	7,353	3,120	–	–
Technical revisions	75	51	(79)	(64)
Closing balance	7,700	3,232	205	67
Proven plus probable reserves				
Opening balance	1,655	1,095	1,559	946
Cash flow	(1,301)	(1,301)	(282)	(282)
Changes in present value	–	110	–	95
Price revisions	121	(88)	81	123
Discoveries and extensions	21,291	12,069		
Technical revisions	39	(24)	297	213
Closing balance	21,805	11,861	1,655	1,095

Subsequent to the year-end, the Company completed the second and third stages of land acquisition in Southwest Saskatchewan, adding a 50% working interest on 5,160 acres in addition to the 50% working interest on the 6,560 acres acquired in 2006. In the first quarter of 2007, the Company drilled an additional 31 wells, all of which were successful. Twenty-five of these wells were brought on production in the first quarter of 2007, bringing the total number of producing wells in the area to 32. The other six wells are behind pipe and are scheduled to be brought on production in the first quarter of 2008.

As the second and third stage land acquisitions in Southwest Saskatchewan were not completed by the year-end, both the acreage and the related reserves at year-end have been significantly increased in the first quarter of 2007.

Taxation

The Company, pursuant to the flow-through share component of its equity issue in the second quarter of 2005, committed to incurring qualifying expenditures of $1,597,745 in 2006. These expenditures were incurred by the end of the first quarter of 2006.

In the second quarter of 2006, the Company raised additional equity of $5,075,000 including a flow-through component where the Company committed to incurring qualifying expenditures of $1,925,000 on or before December 31, 2007. The Company satisfied this commitment by the end of the first quarter of 2007.

The Company, at December 31, 2006, has unused non-capital losses and tax pools as follows:

	December 31, 2006
Non-Capital Losses Carried Forward	**$ 322,320**
Canadian Exploration Expenses (CEE)	**437,505**
Canadian Development Expenses (CDE)	**2,298,831**
Canadian Oil and Gas Property Expenses (COGPE)	**4,582,929**
Undepreciated Capital Costs (UCC)	**7,817,078**
Share Issue Costs	**90,306**
Total	**$ 15,548,969**

Liquidity and Capital Resources

The Company has obtained a revolving production loan from a financial institution, providing the capacity to draw up to $6,000,000. As at December 31, 2006, the Company had drawn only $1,806,000 on the facility.

Subsequent to the year-end, the Company raised gross proceeds of $5.8 million through the issuance of 2,718,750 common shares, including 906,250 common shares issued on a flow-through basis. The proceeds from the issue were used to conduct its drilling programs at Southwest Saskatchewan and Northeast British Columbia.

The Company generated $1,049,728 of funds flow from operations in 2006, an increase of 442% over 2005 levels. Due to the drilling program subsequent to the year-end, and the resulting production increases, the Company expects that this will increase significantly in 2007 over 2006 levels.

Outlook

In the first quarter of 2007, the Company drilled 31 wells of which 25 have been brought on production by March 31, 2007. This increase in the number of producing wells gave the Company a first-quarter exit production figure of 950 boe per day with an additional 210 boe per day behind pipe. The result of this operational expansion is expected to significantly and positively impact the Company's production, revenue, funds flow from operations and net earnings in 2007. In addition, land expansion in Southwest Saskatchewan in the first quarter of 2007 has improved the number of drill-ready locations to 36. These 36 locations, representing nearly a doubling up of the 38 wells that have been drilled to date on the acreage, are highly prospective and are expected to be successful throughout. As a result, management anticipates continuous low-risk growth year-over-year for 2007 and 2008.

Following the evaluation of 3D seismic in the Company's second and third phases at Pembina, the Company is looking to license four locations in addition to the one location that is currently licensed. Wells on this prolific Nisku fairway have produced in excess of 1,000 boe per day and no further crown land in the area is available. The Company has working interests of 7% to 25% on nearly 9,000 acres throughout the area.

The Company's management continues to pursue expansion opportunities to create shareholder value.

Dated: April 25, 2007

Kenway Mack Slusarchuk Stewart LLP
CHARTERED ACCOUNTANTS

Auditors' Report

To: The Shareholders of
Ironhorse Oil & Gas Inc.

We have audited the balance sheets of **Ironhorse Oil & Gas Inc.** as at **December 31, 2006 and 2005** and the statements of operations and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. 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 plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2006 and 2005, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Kenway Mack Slusarchuk Stewart LLP

Calgary, Alberta
April 11, 2007

Chartered Accountants

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Independent Member Firm of DFK International

IRONHORSE OIL & GAS INC.
Balance Sheets

	December 31 2006	December 31 2005
ASSETS		
Current Assets:		
Cash	**$ 8,674**	$ 3,719,903
Accounts receivable	**398,766**	47,323
Prepaid expenses	**38,902**	26,048
	446,342	3,793,274
Property and equipment (note 3)	**16,402,488**	3,730,982
	$ 16,848,830	$ 7,524,256
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 2,977,699**	$ 317,957
Revolving production loan (note 10)	**1,806,000**	–
	4,783,699	317,957
Asset retirement obligation (note 4)	**323,037**	113,140
Future income taxes (note 5)	**788,701**	413,929
	5,895,437	845,026
Shareholders' equity:		
Share capital (note 6)	**14,093,637**	9,620,765
Contributed surplus (note 6)	**854,156**	320,044
Deficit	**(3,994,400)**	(3,261,579)
	10,953,393	6,679,230
	$ 16,848,830	$ 7,524,256

Commitments (note 5)

See accompanying notes to the financial statements.

Approved on behalf of the board:

(signed) "Larry J. Parks" __________
Director

(signed) "Gerry C. Quinn" ________
Director

IRONHORSE OIL & GAS INC.
Statements of Operations and Deficit

	Year ended December 31 2006	Year ended December 31 2005
Revenue	**$ 2,709,734**	$ 493,616
Royalties	**(1,092,481)**	(122,488)
	1,617,253	371,128
Other income	**57,319**	56,890
	1,674,572	428,018
Expenses		
Operations	**316,622**	88,876
General and administration	**288,466**	138,823
Stock-based compensation	**555,628**	278,970
Interest	**11,516**	–
Depletion and amortization	**1,460,410**	46,763
	2,632,642	553,432
Income (loss) before income taxes	**(958,070)**	(125,414)
Future income tax recovery (note 5)	**225,249**	460,890
Net income (loss)	**(732,821)**	335,476
Deficit, beginning of the year	**(3,261,579)**	(3,597,055)
Deficit, end of the year	**$ (3,994,400)**	$ (3,261,579)
Net income per share (note 7)		
Basic	**$ (0.04)**	$ 0.03
Diluted	**$ (0.04)**	$ 0.03

See accompanying notes to the financial statements.

IRONHORSE OIL & GAS INC.
Statements of Cash Flows

	Year ended December 31 2006	Year ended December 31 2005
Cash flows from operations		
Net income (loss)	**$ (732,821)**	$ 335,476
Add (deduct) items not affecting cash		
Depletion and amortization	**1,460,410**	46,763
Future income tax recovery	**(225,249)**	(460,890)
Stock-based compensation	**555,628**	278,970
Abandonment costs incurred	**(8,240)**	(6,566)
Funds flow from operations	**1,049,728**	193,753
Changes in non-cash working capital (note 12)	**(208,731)**	50,638
	840,997	244,391
Cash flows from financing activities		
Issuance of common shares	**5,051,377**	6,325,410
Increase in revolving production loan	**1,806,000**	–
	6,857,377	6,325,410
Cash flows from investing activities		
Expenditures on property and equipment	**(13,913,779)**	(3,434,941)
Changes in non-cash working capital (note 12)	**2,504,176**	188,172
	(11,409,603)	(3,246,769)
Net increase (decrease) in cash during the year	**(3,711,229)**	3,323,032
Cash, beginning of the year	**3,719,903**	396,871
Cash, end of the year	**$ 8,674**	$ 3,719,903

See accompanying notes to the financial statements.

1. NATURE OF OPERATIONS

The Company was incorporated on September 18, 1972 in the Province of British Columbia and was continued under the Alberta Business Corporations Act on November 26, 2002. The Company is in the business of exploration for and production of petroleum and natural gas properties.

2. SIGNIFICANT ACCOUNTING POLICIES

(a) Petroleum and natural gas properties

Capitalized costs

The Company follows the full cost method of accounting, whereby all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized in a single Canadian cost centre. Such amounts include land acquisition costs, geological and geophysical expenditures, carrying charges of non-producing properties, costs of drilling productive and non-productive wells, site restoration and abandonment costs and administrative costs related to exploration and development activities.

Proceeds from the sale of properties are applied against capitalized costs and gains or losses are not recognized in the statement of operations unless the depletion and depreciation rate would be changed by 20% or more.

Impairment test

The Company calculates a ceiling test whereby the carrying value of its property and equipment is compared at each reporting period end to an estimate of undiscounted future net cash flow from the production of gross proved reserves plus the cost of unproven properties and major development projects, net of impairments, excluded from depletion. Net cash flow is estimated using forecast prices, less estimated costs directly associated with the development, production and sale of reserves. Should the ceiling test result in an excess of carrying value, the Company would then measure the amount of impairment by comparing the carrying amounts of property and equipment to an amount equal to the estimated net present value of future cash flows from proved plus probable reserves and the carrying value of unproved properties, net of impairments. A risk-free interest rate is used to arrive at the net present value of the future cash flows. Any excess is recorded as a permanent impairment. Undeveloped and unproved properties are also assessed periodically to determine whether impairment has occurred.

Depletion and amortization

The capitalized costs of petroleum and natural gas properties plus future development costs, if any, are depleted and amortized using the unit-of-production method based on the Company's interest in proved reserves of petroleum and natural gas calculated before royalties. Estimated proved reserves are based on reports prepared by independent engineering consultants. Petroleum substances are converted to volumes of energy equivalent barrels of oil at a conversion rate of six thousand cubic feet ("mcf") of natural gas to one barrel of crude oil.

Costs associated with the acquisition and evaluation of significant unproved properties where there is no commercial production are excluded from amounts subject to depletion until such time as the properties are proved or become impaired.

2. SIGNIFICANT ACCOUNTING POLICIES (continued)

(b) Asset retirement obligation

The Company recognizes and measures the liabilities for obligations associated with the retirement of petroleum and natural gas properties when those obligations result from the acquisition, construction, development or normal operation of the asset. The obligation is measured at fair value and the related costs recorded as part of the carrying value of the related asset. Fair value is estimated using the present value of the estimated future cash costs to reclaim and abandon wells and facilities, using the Company's credit-adjusted risk free interest rate. In subsequent periods, the liability is adjusted for the change in present value and any changes in the amount or timing of the underlying future cash flows required for settlement of the obligation with a corresponding charge to depletion and amortization. The asset retirement costs included in petroleum and natural gas costs are depleted or amortized into income in accordance with the Company's policies pertaining to those assets.

(c) Interests in joint ventures

Substantially all of the Company's petroleum and natural gas exploration and development activities are conducted jointly with others and, accordingly, the financial statements reflect only the Company's proportionate interest in such activities.

(d) Future income taxes

The Company uses the liability method for accounting for future income taxes. Under the liability method, future income tax assets and liabilities are determined based on "temporary differences" (differences between the accounting basis and the tax basis of the assets and liabilities), and are measured using the currently enacted tax rates and laws expected to apply when those differences reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in net income in the period when the change is substantially enacted. A valuation allowance is recorded against any future income tax assets if it is more likely than not that the asset will not be realized.

(e) Flow-through shares

Resource expenditure deductions funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. To recognize the foregone tax benefits to the Company, the future income tax liability and the carrying value of the shares issued are adjusted by the effect of the tax benefits renounced to subscribers in the period when the corresponding exploration and development expenditures are renounced.

(f) Stock-based compensation

The Company follows the fair value method to record 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 granting. For options granted in respect of future services, compensation expense is recorded over the vesting period.

(g) Revenue recognition

Revenue from the production of petroleum and natural gas is recognized when deliveries of products are made to third parties.

2. SIGNIFICANT ACCOUNTING POLICIES (continued)

(h) Use of estimates

Management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reported period. The amounts recorded for depletion and amortization of petroleum and natural gas properties and the provision for the asset retirement obligation and the ceiling test are based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. The fair value of stock options and the related stock-based compensation expense is based on estimates using the Black-Scholes option pricing model. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

(i) Net income per share

Diluted per share amounts are calculated using the treasury stock method. Diluted calculations reflect the incremental common shares that would be issued upon exercise of dilutive options, warrants and equivalents assuming the proceeds would be used to repurchase shares at average market prices for the period. Anti-dilutive items are not included in the calculation.

(j) Financial instruments

The Company uses derivative financial instruments to manage its exposure to volatility in commodity prices. These financial instruments are not used for trading or other speculative purposes. Commodity price financial instruments are recorded at fair value on inception. Realized gains and losses on financial instruments not formally designated as a hedge are reflected as adjustments to the related revenue when the gain or loss is realized; unrealized gains and losses on these instruments are recognized as adjustments to the related revenue at the end of each reporting period. The estimated fair value of these instruments is based on quoted market prices, or if quotes are not available, third party market indications and forecasts are used.

3. PROPERTY AND EQUIPMENT

	December 31, 2006		
	Cost	**Accumulated Depletion and Amortization**	**Net**
Petroleum and natural gas properties	**$18,010,747**	**$ 1,608,259**	**$16,402,488**

	December 31, 2005		
	Cost	Accumulated Depletion and Amortization	Net
Petroleum and natural gas properties	$ 3,888,784	$ 157,802	$ 3,730,982

3. PROPERTY AND EQUIPMENT (continued)

In conducting the ceiling test as at December 31, 2006, the Company's estimated future cash flows exceeded the carrying value of the related petroleum and natural gas properties, after using certain assumptions pertaining to future commodity prices. Assumptions for crude oil and natural gas sales prices at the wellhead in Canadian dollars are consistent with the Company's December 31, 2006 reserve report as provided by GLJ Petroleum Consultants and are detailed below:

	Oil ($/barrel)	Gas ($/mcf)
2007	$ 63.28	$ 6.73
2008	61.03	7.01
2009	58.78	7.30
2010	57.53	7.35
2011	57.53	7.40
Thereafter	58.03 – 70.02	7.70 – 9.36

During the year ended December 31, 2006, the Company has capitalized interest in the amount of $ nil (December 31, 2005 – $27,730) and general and administrative costs of $185,014 (December 31, 2005 – $ nil).

An estimated future capital cost of $7,736,000 (December 31, 2005 – $ nil), required for properties to which proven reserves have been attributed, has been added to property and equipment costs for depletion purposes. Costs relating to unproved properties of $5,191,878 (year ended December 31, 2005 – $3,446,145), including $3,012,191 (December 31, 2005 – $ nil) of facilities and infrastructure pertaining to future development projects anticipated to be completed subsequent to year-end, have been excluded from property and equipment costs for depletion purposes.

4. ASSET RETIREMENT OBLIGATION

	Year ended December 31 2006	Year ended December 31 2005
Asset retirement obligation, beginning of the year	**$ 113,140**	$ 109,151
Incurred in the year	**208,184**	5,515
Expenditures made on asset retirements	**(8,240)**	(6,566)
Change in present value during period	**9,953**	5,040
Asset retirement obligation, end of the year	**$ 323,037**	$ 113,140

The total undiscounted amount of cash flows required to settle the obligations as measured at December 31, 2006 is estimated to be $869,910 (December 31, 2005 - $163,921). These obligations are expected to be settled at various times over the 17 years subsequent to December 31, 2006. The credit-adjusted risk free rate at which the estimated cash flows were discounted was 8% during the year ended December 31, 2006 (December 31, 2005 – 8 %) and the estimated inflation rate used to project future costs was 1.5% (December 31, 2005 – 1.5 %).

5. INCOME TAXES

	Year ended December 31 2006	Year ended December 31 2005
Statutory tax rate	**32.12%**	37.62%
Anticipated tax expense (recovery)	**$ (307,732)**	$ (47,181)
Increase (decrease) resulting from:		
Non-deductible crown royalties	**7,262**	26,008
Non-deductible stock-based compensation	**178,468**	104,949
Resource allowance	**(43,169)**	(14,630)
Tax rate changes	**(60,344)**	3,522
Other	**(266)**	–
Valuation allowance	**–**	(533,558)
Future tax expense (recovery)	**$ (225,249)**	$ (460,890)

During the year ended December 31, 2005, the Company recorded a reversal of the remaining valuation allowance as the Company's remaining tax pools will more likely than not be utilized in future periods.

The components of the net future tax liability are as follows:

	December 31 2006	December 31 2005
Future income tax assets related to:		
Non-capital losses	**$** 103,530	$ 206,657
Asset retirement obligations	103,759	42,563
Share issue costs	29,006	22,449
Total future income tax assets	236,295	271,669
Future income tax liabilities related to:		
Property and equipment	(1,024,996)	(685,598)
Future income tax asset (liability)	**$** (788,701)	$ (413,929)

Pursuant to the Company's share issue in the year ended December 31, 2006, the Company has committed to renounce to investors qualifying expenditures incurred prior to December 31, 2007 of $1,925,000. As at December 31, 2006, the Company has remaining commitments to incur $1,833,338 of qualifying expenditures prior to December 31, 2007.

6. SHARE CAPITAL

The Company has authorized unlimited common shares and unlimited first preferred shares. The outstanding share capital is as follows:

(a) Common Shares

	Year ended December 31, 2006	
	Number	**Amount**
Balance, beginning of the year	**14,871,558**	**$ 9,620,765**
Issued during the year	**1,495,834**	**3,204,833**
Issued on a flow-through basis during the year	**700,000**	**1,925,000**
Share issue costs	**–**	**(56,940)**
Tax effect of flow-through shares issued	**–**	**(618,310)**
Tax effect of share issue costs	**–**	**18,289**
Balance, end of the year	**17,067,392**	**$14,093,637**

	Year ended December 31, 2005	
	Number	Amount
Balance, beginning of the year	8,871,558	$ 4,170,174
Issued during the year	4,000,000	4,000,000
Issued on a flow-through basis during the year	2,000,000	2,400,000
Share issue costs	–	(74,590)
Tax effect of flow-through shares issued	–	(902,880)
Tax effect of share issue costs	–	28,061
Balance, end of the year	14,871,558	$ 9,620,765

At December 31, 2006, the Company is holding 7,049 common shares in escrow arising from an agreement that provides for a release subject to approval by regulatory authorities. At December 31, 2005, the Company held 679,049 common shares in escrow arising from two escrow agreements. The first agreement provides for the escrow of 7,049 shares subject to release upon approval by regulatory authorities. The second provided for the escrow of 2,240,000 shares issued pursuant to an asset purchase and sale closed June 27, 2003. The terms of this escrow agreement included a release of the shares from escrow over a three year period that ended on August 5, 2006.

6. SHARE CAPITAL (continued)

(b) Stock Options

Under the Company's stock option plan, common share purchase options may be granted to directors, officers, staff and consultants. The Company may grant options to purchase common shares up to a maximum of 10% of the number of issued and outstanding common shares. The granted common share purchase options are subject to vesting requirements as determined upon granting and are subject to expiry five years following the date granted.

	Year ended December 31, 2006			Year ended December 31, 2005		
	Number Outstanding		**Weighted Avg Price Per Share**	Number Outstanding		Weighted Avg Price Price Per Share
Balance, beginning of the year	**1,483,500**	**$**	**0.884**	580,000	$	0.275
Granted during the year	**264,000**		**2.946**	903,500		1.274
Exercised during the year	**(95,834)**		**0.348**	–		–
Balance, end of the year	**1,651,666**	**$**	**1.244**	1,483,500	$	0.884
Exercisable, end of the year	**718,666**	**$**	**0.675**	320,000	$	0.257

The following table summarizes information about the Company's stock options outstanding:

	December 31, 2006			December 31, 2005		
Exercise Price	**Options Outstanding**	**Amounts Vested**	**Remaining Contractual Life (Years)**	Options Outstanding	Amounts Vested	Remaining Contractual Life (Years)
$0.225	**360,000**	**360,000**	**2.0**	380,000	253,333	3.0
0.370	**200,000**	**133,333**	**2.1**	200,000	66,667	3.1
0.380	**207,666**	**18,666**	**3.1**	283,500	–	4.1
1.680	**615,000**	**205,000**	**3.5**	615,000	–	4.5
2.070	**5,000**	**1,667**	**3.9**	5,000	–	4.9
2.860	**12,500**	**–**	**4.4**	–	–	–
2.950	**251,500**	**–**	**4.4**	–	–	–

Assumptions used in the calculation of the weighted average fair value of options granted are as follows:

Year ended		**December 31 2006**		December 31 2005
Options granted during the year		**264,000**		903,500
Risk-free interest rate		**5.0%**		4.0%
Expected life		**5 years**		5 years
Average volatility		**80%**		98%
Anticipated dividends		**none**		none
Weighted-average fair value per option	**$**	**1.98**	$	0.89

6. SHARE CAPITAL (continued)

(c) Contributed Surplus

	Year ended December 31 2006	Year ended December 31 2005
Contributed surplus, beginning of the year	**$ 320,044**	$ 41,074
Stock-based compensation charged during the year	**555,628**	278,970
Amounts charged to share capital during the year	**(21,516)**	–
Contributed surplus, end of the year	**$ 854,156**	$ 320,044

7. PER SHARE AMOUNTS

Basic per share amounts are calculated using the weighted average number of common shares outstanding during the year ended December 31, 2006 of 16,346,171 (year ended December 31, 2005 – 11,912,654).

Options to purchase 1,651,666 common shares were outstanding at December 31, 2006 (1,483,500 – December 31, 2005), 1,387,666 of which were potentially dilutive (year ended December 31, 2005 – 863,500) and which have not been included in the computation of earnings per share as the effect would be anti-dilutive.

The following table sets forth the details of the denominator used for the computation of basic and diluted earnings per share:

	Year ended December 31 2006	Year ended December 31 2005
Basic weighted average number of common shares	**16,346,171**	11,912,654
Net effect of dilutive securities		
Stock options	**–**	643,532
Diluted weighted average number of common shares	**16,346,171**	12,556,186

8. RELATED PARTY TRANSACTIONS

(a) Administrative Services Contract

The Company is subject to an administrative services contract with Grizzly Resources Ltd., a company related by virtue of common management. These services are in the normal course of business and are recorded at the exchange amount which is the amount of consideration established and agreed to by the related parties. The contract charges the Company for services is based on a fee production unit and a percentage of capital expenditures.

	Year ended December 31 2006	Year ended December 31 2005
Administrative services contract	**$ 297,436**	$ 40,910
Less amounts capitalized	**(185,014)**	–
Administrative services expensed	**$ 112,422**	$ 40,910

As at December 31, 2006, $76,878 (December 31, 2005 – $24,734) related to these services was included in accounts payable and accrued liabilities.

(b) Acquisition

Grizzly Resources Ltd. was the vendor of certain undeveloped petroleum and natural gas properties acquired in the year ended December 31, 2005. An amount of $2,525,524 was recorded pursuant to the acquisition of property and equipment in that year. Grizzly Resources Ltd. is a significant joint venture partner on those lands. This acquisition was not in the normal course of business and was recorded at the exchange amount which is the amount of consideration established and agreed to by the related parties. No amounts related to this acquisition were included in accounts payable and accrued liabilities as at December 31, 2005.

(c) Joint Venture Operator

The joint venture operator of the majority of the petroleum and natural gas properties owned by the Company is Grizzly Resources Ltd. As operator, in accordance with industry standards for joint interest billings, Grizzly charged $176,918 (year ended December 31, 2005 – $ nil) in overhead administration.

(d) Royalty Payments

The Company is subject to an overriding royalty agreement with a member of the Company's board of directors on one of the Company's operating areas. The agreement provides for a 2% overriding royalty on revenue earned within the area. During the year, $29,457 (2005 – $ nil) was paid in royalties through this contract. As at December 31, 2006, $19,052 related to this contract was included in accounts payable and accrued liabilities.

9. NON-MONETARY TRANSACTION

In the year ended December 31, 2005, the Company exchanged certain working interests in undeveloped acreage with a third party for new working interests in additional acreage in one of the Company's operating fields. The exchange was recorded at the carrying value of the assets and no gain or loss on the exchange was recorded.

10. REVOLVING PRODUCTION LOAN

	Year ended December 31 2006	Year ended December 31 2005
Balance, beginning of year	**$ –**	$ –
Amounts advanced, net of repayments	**1,806,000**	–
Balance, end of year	**$ 1,806,000**	$ –

The Company has a revolving production loan facility to a maximum of $6,000,000 with a financial institution (December 31, 2005 - $400,000). The amount outstanding bears interest at the financial institution's prime rate per annum on the first $3,000,000 and at the financial institution's prime rate plus 0.75% per annum on the amounts outstanding above $3,000,000. The facility is secured by a general security agreement providing coverage over all present and after acquired property of the Company.

11. FINANCIAL INSTRUMENTS

Fair value

The Company's carrying values of cash, accounts receivable, accounts payable and accrued liabilities and its revolving production loan approximates their fair values due to the immediate or short-term maturity of these instruments.

Credit risk

The majority of the accounts receivable are in respect of oil and natural gas operations. The Company generally extends unsecured credit to these customers, and therefore, the collection of accounts receivables may be affected by changes in economic or other conditions. Management believes the risk is mitigated by the size and reputation of the companies to which they extend credit. The Company has not experienced any credit loss in the collection of receivables to date.

Interest rate risk

The Company is exposed to the risk of interest rate fluctuations on the amounts drawn on its revolving production loan. The outstanding loan bears interest that is based on the financial institution's prime rate or a factor based on the financial institution's prime rate.

11. FINANCIAL INSTRUMENTS (continued)

Commodity prices and exchange rate risk

The nature of the company's operations results in exposure to fluctuation in commodity prices and exchange rates. The Company entered into a costless collar contract, effective November 1, 2006 to March 31, 2007. The collar contract provided the Company with a floor sales price of $8.00 per gigajoule (GJ) and a ceiling of $11.10 per GJ of natural gas on 625 GJ per day during the period.

	Year ended December 31 2006	Year ended December 31 2005
Amounts collected (paid) as a result of contracts during the year	**$ 36,318**	$ –
Unrealized gain on contract at year-end	**90,000**	–
Net increase (reduction) to revenue from contracts during the year	**$ 126,318**	$ –

The unrealized gain has been included in accounts receivable and revenue accordingly.

12. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	Year ended December 31 2006	Year ended December 31 2005
Changes in non-cash working capital		
Accounts receivable	**$ (351,443)**	$ (12,782)
Prepaid expenses	**(12,854)**	(21,079)
Accounts payable and accrued liabilities	**2,659,742**	272,671
Total changes in non-cash working capital	**2,295,445**	238,810
Less changes in non-cash working capital from investing	**(2,504,176)**	(188,172)
Changes in non-cash working capital from operations	**$ (208,731)**	$ 50,638

13. SUBSEQUENT EVENTS

(a) Royalty Agreement Repurchased

On January 15, 2007, the Company negotiated a purchase of the overriding royalty due to a member of the Company's board of directors for a price of $550,000. The Company paid $250,000 and received the right to an outstanding receipt of $19,052 on the closing date. The Company is obligated to pay the balance upon obtaining title to certain expansion lands within the royalty area.

(b) Non-Brokered Private Placement

On January 30, 2007, the Company issued 2,718,750 common shares, including 906,250 common shares issued on a flow-through basis, in a non-brokered private placement for aggregate proceeds of $5,800,000. The funds were utilized in the drilling programs in two of its operating areas.

(c) Normal Course Issuer Bid

Commencing April 1, 2007, the Company received regulatory approval to re-purchase a maximum of 1,236,869 of its shares in the market for the purposes of cancellation. To April 11, 2007, the Company has re-purchased 27,200 common shares pursuant to the issuer bid.

BOARD AND MANAGEMENT

Directors

Larry J. Parks, Chairman
Blaine C. Favel
Jeff Lawson
Gerry C. Quinn
James K. Wilson

Officers

Larry J. Parks, President & Chief Executive Officer
Alan G. Withey, VP Finance & CFO
D. Craig Boland, VP Exploration
William G. Manley, VP Engineering & Operations
James K. Wilson, VP & Corporate Secretary

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