

INTERNATIONAL SOVEREIGN ENERGY CORP.

Management's Discussion and Analysis

Form 51-102F2

**For the Three and Nine Months Ended
September 30, 2009**

November 11, 2009

The following is Management’s Discussion and Analysis (“MD&A”) of the operating and financial results of International Sovereign Energy Corp. (the “Company” or “ISR”) for the three and nine months ended September 30, 2009 and 2008 as well as information concerning the Company’s future outlook based on currently available information. This MD&A should be read in conjunction with the Company’s unaudited interim consolidated financial statements and the accompanying notes for the periods ended September 30, 2009 and 2008 and the audited Consolidated Financial Statements, related notes and Management’s Discussion and Analysis for the years ended December 31, 2008 and 2007.

Basis of Presentation –The financial data presented below has been prepared in accordance with Canadian Generally Accepted Accounting Principles (“GAAP”). The reporting and the measurement currency is the Canadian dollar. For the purpose of calculating unit costs, natural gas is converted to a barrel equivalent (“boe”) using six thousand cubic feet of natural gas equal to one barrel of oil unless otherwise stated. The following MD&A compares the results of the nine months ended September 30, 2009 to the nine months ended September 30, 2008 and the results of the three months ended September 30, 2009 to the three months ended September 30, 2008.

Non-GAAP Measurements – Within the MD&A references are made to terms commonly used in the oil and gas industry. Funds from operations, funds from operations per share and netbacks are not defined by GAAP in Canada and are referred to as non-GAAP measures. Funds from operations per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of net income per share. Netbacks equal total revenue less royalties and operating and transportation expenses calculated on a per boe basis. Management utilizes these measures to analyze operating performance and leverage. Funds from operations is not intended to represent operating profit for the period nor should it be viewed as an alternative to operating profit, net income, cash flow from operations or other measures of financial performance calculated in accordance with Canadian GAAP. Funds from operations is commonly referred to as cash flow by research analysts and is used to value and compare oil and gas companies and is frequently included in published research when providing investment recommendations. Total boes are calculated by multiplying the daily production by the number of days in the period.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009 \$	2008 \$	2009 \$	2008 \$
Cash flow from operations	417,466	3,577,011	536,556	8,358,026
Changes in non-cash working capital	(709,646)	(732,751)	(1,406,707)	(2,381,262)
Funds from (used in) operations	(292,180)	2,844,260	(870,151)	5,976,764

Forward Looking Statements – Certain statements contained within the Management’s Discussion and Analysis, and in certain documents incorporated by reference into this document, constitute forward looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward looking statements. Forward looking statements are often, but not always, identified by the use of words such as “seek”, “anticipate”, “budget”, “plan”, “continue”, “estimate”, “expect”, “forecast”, “may”, “will”, “project”, “predict”, “potential”, “targeting”, “intend”, “could”, “might”, “should”, “believe”, and other similar expressions. These statements reflect management’s current beliefs and are based on information currently available to management. Forward looking statements involve known and unknown risks, uncertainties and other factors that may cause actual results of events to differ materially from those anticipated in these forward looking statements.

In particular, this MD&A contains the following forward looking statements pertaining to, without limitation, the following: ISR’s future production volumes and the timing of when additional production volumes will come on stream; ISR’s realized price of commodities in relation to reference prices; the Company’s future commodity mix; future commodity prices; the Company’s expectations regarding future royalty rates and the realization of royalty incentives; ISR’s expectation of future operating costs on a per unit basis; the relationship of ISR’s interest expense and the Bank of Canada interest rates; future

general and administrative expenses; future development and exploration activities and the timing thereof; the future tax liability of the Company; the expected decrease to the depletion, depreciation and accretion rate; the estimated future contractual obligations of the Company and the amount expected to be incurred under its farm-in commitments; the estimated future capital expenditure of the Company; the future liquidity and financial capacity of the Company; and its ability to fund its working capital and forecasted capital expenditures. In addition, statements relating to “reserves” or “resources” are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future.

With respect to the forward looking statements contained in the MD&A, ISR has made assumptions regarding future commodity prices; the impact of royalty regimes and certain royalty incentives, the timing and the amount of capital expenditures; production of new and existing wells and the timing of new wells coming on stream; future proved finding and development costs; future operating expenses including processing and gathering fees; the performance characteristics of oil and natural gas properties; the size of oil and natural gas reserves; the ability to raise capital and to continually add to reserves through exploration and development; the continued availability of capital, undeveloped land and skilled personnel; the ability to obtain equipment in a timely manner to carry out exploration and development activities; the ability to obtain financing on acceptable terms; the ability to add production and reserves through exploration and development activities; and the continuation of the current tax and regulation.

We believe the expectations reflected in those forward looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward looking statements included in, or incorporated by reference into this MD&A should not be unduly relied upon. These statements speak only as of the date of this MD&A or as of the date specified in the documents incorporated by reference into this Management’s Discussion and Analysis, as the case may be. The actual results could differ materially from those anticipated in these forward looking statements as a result of the risk factors set forth below and elsewhere in the Management’s Discussion and Analysis; volatility in market prices for oil and natural gas; counterparty credit risk; access to capital; changes or fluctuations in production levels; liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; stock market volatility and market valuation of ISR stock; geological, technical, drilling and processing problems; limitations on insurance; changes in environmental or legislation applicable to our operations, and our ability to comply with current and future environmental and other laws; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; and the other factors discussed under “Risk Factors” in our Annual Information Form filed on SEDAR. Readers are cautioned that the foregoing list of factors are not exhaustive. The forward looking statements contained in this MD&A and the documents incorporated by reference herein are expressly qualified by this cautionary statement. The forward looking statements contained in this document speak only as of the date of this document and ISR does not assume any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable securities laws. This Management’s Discussion and Analysis is dated as of November 11, 2009.

Additional information relating to International Sovereign Energy Corp. is filed on SEDAR and can be viewed at www.sedar.com. Information can also be obtained by contacting the Company at International Sovereign Energy Corp., 1750, 801 – 6th Avenue S.W., Calgary, Alberta T2P 3W2 or by accessing the website at www.isove.com.

ISR is a Canadian based petroleum and natural gas exploration and production company. The Company is active in the exploration and development of hydrocarbon reserves in Western Canada, primarily in low to medium risk exploration and exploitation opportunities. This approach provides the Company with a substantial asset base from which to identify and pursue late stage exploration or early stage development opportunities internationally.

Overall Performance

Revenue for nine months ending September 30, 2009 was \$6,528,200, compared to \$14,930,133 for nine months ending September 30, 2008 representing a decrease of 56%. Average production increased from 863 boe per day in 2008 to 922 boe per day in 2009, an increase of 7%. Average oil prices received in the nine month period decreased by 42% to \$57.57 per bbl in 2009 from \$99.98 per bbl for the same nine month period in 2008. The average gas price received for the nine months ending in 2009 was \$3.70 per mcf compared to \$8.68 per mcf for the same nine months ending September 30, 2008, representing a 57% decrease.

Average oil production for the third quarter of 2009 was 74 bbls per day as compared to 153 bbls per day in the third quarter of 2008. The decrease of 52% in oil production was primarily due to the watering out of the Marwayne oil field. During the same period, average gas production decreased 1% from 4,628 mcf per day in 2008 to 4,577 mcf per day in 2009.

Summary

For the nine months ended September 30, 2009, the Company operated a sustainable oil and gas business. Despite economic challenges, commodity prices for oil products recovered to \$50-\$60 per bbl level. Prices of natural gas however did not show the same level of recovery and prices hovered around \$3-\$4 per mcf going down to a low of \$2.63 during the nine month period.

On May 27, 2009 the Company was informed by Mari Gas Company Limited ("MGCL"), the operator of the Sukkur Block with a 50% working interest ("WI"), and Sujawal Block with a 85% WI, that the Company was in default of non-payment of cash calls of its 15% WI in these Blocks if payment of all outstanding cash calls of approximately US\$1.9 million were not paid within 7 days. Under the Joint Operating Agreement ("JOA"), the Company has the right to remedy the default during a period of 60 days by making payment of all its share of the cash calls with interest at 3% over LIBOR or forfeit its WI. In the event of forfeiture, the Company will not be entitled to receive any consideration for such forfeited WI.

The Company had taken a provision of \$2.8 million in 2008 against international expenditures in Pakistan. The Company has provided for the capital expenditures and the cash calls relating to these Blocks. In addition the Company had posted performance bonds of \$334,703 (PKR 25,966,080 or US\$310,588) and \$482,490 (US\$450,000), which have been fully provided for in the third quarter. In the third quarter of 2009, the Company made an additional provision for \$776,300 (US\$725,000) for farm in costs claimed by MGCL.

The Company is of the opinion that capital is presently better spent on its domestic drilling program that currently has a higher success rate coupled with substantially shorter payback periods. The Company has thus elected not to remedy the default, but to seek out parties that would take over its obligations. Although the Koonj well, in the Sukkur Block, drilled in July 2008 has proven reserves, the operator has yet to start production despite assurances made in November 2008. The Company is not confident that the production will commence in a timely manner, and is concerned that the initial reserve estimates subsequent to drilling have been downgraded substantially.

On August 1, 2009 the Company was granted a temporary injunction until August 8th 2009 that stays MGCL and Petroleum Exploration (Pvt) Limited ("PEL") from forfeiture of the Company's WI in the Sukkur Block.

On September 2, 2009 the Company filed application for contempt of court and the court issued initial contempt notices to the Company's working interest partners in the Sukkur Block, who have ignored the injunction and have tried to forfeit the Company's working interest. The notices were successfully issued on September 4, 2009 with a hearing date set for September 9, 2009, which has now been adjourned to October 31, 2009 adjourned again to November 5, 2009 and further adjourned to November 23, 2009.

On October 3, 2009 the Company was granted a temporary injunction until October 5, 2009, subsequently adjourned to October 31, 2009, that stays MGCL from seeking forfeiture of the Company's WI in the Sujawal Block. The date now fixed for arguments on the injunction application for Sukkur Block and for written statement of MGCL in Sujawal Block is November 5, 2009 and adjourned to November 23, 2009.

On September 29, 2009 the Company received a deposit of US\$100,000 in escrow thereby accepting a non-binding letter of intent to sell its interest in the Charapa Marginal Oil Field ("Charapa") in Ecuador. Subject to due diligence and negotiation of a definitive agreement, the consideration for the purchase of Charapa includes US\$3.0 million and replacement of the Company's performance guarantee of \$2.51 million (US\$2.34 million) to Petroecuador. On October 15, 2009 the Company granted an extension to October 30, 2009 to the potential purchaser of its interest in Charapa to complete its due diligence and then move to a definitive agreement.

On October 31, 2009 the Company executed a Memorandum of Understanding to sell its oil and gas interests in Ecuador to the same potential purchaser noted above and finalize a Purchase and Sale Agreement with a scheduled closing date on or before November 30, 2009.

Overview

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Petroleum and natural gas (\$)	1,874,929	5,563,108	6,528,200	14,930,133
Funds from (used in) operations (\$) ⁽¹⁾	(292,180)	2,844,260	(870,151)	5,976,764
basic per share	(0.02)	0.20	(0.05)	0.43
diluted per share	(0.02)	0.18	(0.05)	0.40
Net earnings (loss) (\$)	(2,192,399)	1,149,935	(5,228,971)	(2,140,583)
basic per share	(0.14)	0.08	(0.32)	(0.15)
diluted per share	(0.14)	0.07	(0.32)	(0.14)
Working capital (deficit) (\$)	(4,078,141)	791,784	(4,078,141)	791,784
Capital expenditures (\$)	785,592	1,146,406	3,225,956	4,283,970
Weighted average number of shares outstanding				
Basic	16,096,084	14,210,867	16,096,084	14,023,033
Diluted	16,096,084	15,416,192	16,096,084	14,984,575
Shares outstanding				
Basic	16,096,084	16,096,084	16,096,084	16,096,084
Diluted	16,931,084	16,726,084	16,931,084	16,726,084
Average production				
Natural gas (mcf/d)	4,577	4,628	4,874	3,870
Crude oil (bbls/d)	74	153	95	174
Natural gas liquids (bbls/d)	10	42	11	44
BOE (boe/d) (6:1)	847	967	922	863
Average realized prices ⁽²⁾				
Natural gas (mcf/d)	3.05	8.03	3.70	8.68
Crude oil (bbls/d)	81.02	128.25	57.57	99.98
Natural gas liquids (bbls/d)	40.32	88.04	38.32	79.26
BOE (boe/d) (6:1)	24.07	62.53	25.92	63.14
Netback (\$/boe) ⁽³⁾				
Petroleum and natural gas	24.07	62.53	25.92	63.14
Royalties	(4.26)	10.45	2.38	11.95
Operating expenses	12.30	10.79	8.65	9.64
Transportation costs	2.86	2.95	2.10	2.01
Operating netback	13.17	38.34	12.79	39.54

(1) Funds from operations is a non-GAAP measure that does not have a standardized meaning as prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other oil and gas companies. We consider it an important measure as it demonstrates our ability to generate the cash flow necessary to fund future growth through capital investment.. Throughout this MD&A funds from operations is defined as cash provided by operating activities before the changes in non-cash working capital.

(2) Average realized prices are before transportation costs.

(3) Operating netback is a non-GAAP measure that does not have a standardized meaning as prescribed by GAAP. We consider it an important measure as it demonstrates our operating efficiency and ability to generate the cash flow necessary to fund future growth through capital investment.

Funds from Operations and Net Earnings (Loss)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2009	2008	2009	2008
	\$	\$	\$	\$
Funds from (used in) operations	(292,180)	2,844,260	(870,151)	5,976,764
Per share:				
Basic (\$)	(0.02)	0.20	(0.05)	0.43
Diluted (\$)	(0.02)	0.18	(0.05)	0.40

Funds used in operations for the third quarter of 2009 were \$292,180, a 110% decrease from the third quarter of 2008. The decrease is largely due to lower commodity prices, lower revenues, abandonment expenditures of \$65,967 incurred in the third quarter of 2009 (2008-\$1,241), and provision made against potential obligations in Pakistan. For nine months, funds used in operations were \$870,150 compared to funds from operations of \$5,976,764 for the same period in 2008, due to lower commodity prices, abandonment expenditures amounting to \$789,838 compared to \$14,416 in 2008, and provision made against potential obligations in Pakistan. Without these provisions the Company would have generated funds from operations of \$611,053 and \$987,147 in the three and nine month periods ending September 30, 2009 respectively.

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2009	2008	2009	2008
	\$	\$	\$	\$
Net earnings (loss)	(2,192,399)	1,149,935	(5,228,971)	(2,140,583)
Per share:				
Basic (\$)	(0.14)	0.08	(0.32)	(0.15)
Diluted (\$)	(0.14)	0.07	(0.32)	(0.14)

The Company incurred a net loss of \$2,192,399 for the third quarter of 2009 compared to net earnings of \$1,149,935 for the same period in 2008. The decrease in net earnings is primarily due to lower commodity prices, Pakistan asset impairment and related obligations of \$903,233, and an increase in domestic depletion due to reserve evaluation assessments. For the nine month period, the Company had a net loss of \$5,228,971 compared to a net loss of \$2,140,583 for the same period in 2008. The reduction in net earnings is due to lower commodity prices, provision related to Pakistan assets and obligations, higher depletion and depreciation, as compared to 2008.

Petroleum and Natural Gas

Sales volumes

		Three Months Ended		Nine Months Ended	
		September 30,		September 30,	
		2009	2008	2009	2008
Natural gas	<i>mcf/d</i>	4,577	4,628	4,874	3,870
Crude oil	<i>bbl/d</i>	74	153	95	174
Natural gas liquids	<i>bbl/d</i>	10	42	11	44
Combined (6:1)	<i>boe/d</i>	847	967	922	863

Total average sales production was 847 boe per day for the third quarter of 2009 compared to 967 boe per day for the third quarter of 2008 representing a decrease of 12%. During the quarter six gas wells were shut-in awaiting recovery of natural gas prices. Three of these wells were opened up mid-November 2009 and are now producing. Production for the third quarter of 2009 was weighted approximately 90% natural gas and 10% crude oil and liquids.

For nine months, average production was 922 boe per day as compared to 863 boe per day for the same period in 2008. For the nine month period however, natural gas volumes increased by 26% as the Company added new production in the Berwyn area, late in 2008. Quarter to quarter and year to date comparison of oil and liquids volumes indicates decreasing production due to the watering out of the Marwayne field. Management expects production to remain constant from its current producing wells for the remainder of the year. Petroleum prices have shown signs of recovery; however natural gas prices continue to lag far behind.

Revenues

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2009	2008	2009	2008
	\$	\$	\$	\$
Natural gas	1,286,233	3,417,617	4,920,066	9,208,000
Crude oil	551,605	1,805,289	1,493,061	4,766,582
Natural gas liquids	37,091	340,202	115,073	955,551
Total	1,874,929	5,563,108	6,528,200	14,930,133

Petroleum and gas revenue was \$1,874,929 for the three months ended September 30, 2009 representing a 66% decrease from the third quarter of 2008. The decrease is due to lower natural gas prices and lower average production. For the nine month period, petroleum and natural gas revenue was \$6,528,200 compared to \$14,930,133 for the same period in 2008 despite an increase in production of 7%. The decrease is due to lower crude oil and natural gas prices.

Average Realized Prices ⁽¹⁾

		Three Months Ended		Nine Months Ended	
		September 30,		September 30,	
		2009	2008	2009	2008
Natural gas	<i>\$/mcf</i>	3.05	8.03	3.70	8.68
Crude oil ⁽²⁾	<i>\$/bbl</i>	81.02	128.25	57.57	99.98
Natural gas liquids	<i>\$/bbl</i>	40.32	88.04	38.32	79.26
Combined (6:1)	<i>\$/boe</i>	24.07	62.53	25.92	63.14

(1) Average realized prices are before transportation costs.

(2) Estimates of crude oil prices in the previous quarter were low.

Benchmark pricing

		Three Months Ended		Nine Months Ended	
		September 30,		September 30,	
		2009	2008	2009	2008
		\$	\$	\$	\$
AECO natural gas (Daily index)	<i>Cdn\$/GJ</i>	2.78	8.76	3.59	8.13
AECO natural gas (Monthly spot)	<i>Cdn\$/GJ</i>	2.87	8.23	3.89	8.19
WTI crude oil	<i>US\$/Bbl</i>	68.19	118.21	56.86	113.34
Edmonton par crude oil	<i>Cdn\$/Bbl</i>	71.71	122.47	62.68	115.82
Hardisty heavy crude oil	<i>Cdn\$/Bbl</i>	64.44	98.02	52.85	88.22
Exchange rate	<i>US\$/Cdn\$</i>	0.9117	0.9604	0.8580	0.9822

The Company's realized natural gas price was \$3.05 per mcf for the third quarter of 2009 as compared to a realized price of \$8.03 per mcf during the third quarter of 2008. Year to date, the Company realized a natural gas price of \$3.70 per mcf compared to \$8.68 per mcf for the same period in 2008.

Average crude oil prices during the third quarter of 2009 were \$81.02 per bbl representing a 37% decrease from realized crude oil prices in the third quarter of 2008. The year to date realized crude oil price was \$57.57 per bbl represented a 42% decrease from the same period in 2008.

Royalties

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2009	2008	2009	2008
	\$	\$	\$	\$
Crown	(371,500)	671,229	462,210	2,077,110
Freehold	25,688	196,825	74,031	556,620
Gross overriding	14,280	61,758	62,008	192,311
Total	(331,532)	929,812	598,249	2,826,041
As % of oil and gas revenues	(18)	17	9	19
\$/boe (6:1)	(4.26)	10.45	2.38	11.95

Royalty expense consists of royalties paid to the provincial governments, freehold land owners and overriding royalty owners. For the three months ended September 30, 2009 total royalties were (\$331,532) or (\$4.26) per boe compared to approximately 17% of total revenue during the third quarter of 2008. The recoverable royalty in the third quarter of 2009 was due to the impact of Gas Cost Allowance ("GCA") related to 2008 that was received during the period. Year to date, royalties as a percentage of oil and gas revenue were 9% compared to 19% in the corresponding period due to the effect of GCA and lower commodity prices.

GCA is a term which describes a payment by the Government of Alberta (the "Province") to recognize capital and operating expenditures which are incurred in the gathering and processing of the Province's royalty share of natural gas production.

On January 1, 2009 the Government of Alberta implemented its New Royalty Framework ("NRF") and subsequently introduced a Transitional Royalty Framework ("TRF") for new wells producing subsequent to January 1, 2009 until December 31, 2013. Both the NRF and TRF are sensitive to commodity prices and production levels, therefore ISR's corporate royalty rates will fluctuate with commodity prices, well production rates, and decline of existing wells, performance and the location of new wells drilled. Depending upon future commodity prices and drilling plans, it is possible that the NRF and TRF could increase future royalty rates with a corresponding decrease to future operating netbacks, funds from operations and the net present value of reserves. Future reserve and production addition activities could be impacted by the NRF and TRF.

On June 25, 2009, the Government of Alberta announced an extension of previously announced royalty incentive programs by one year to March 2011 in light of current global economic conditions. The programs included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program, a \$200 per meter royalty credit will be available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2011, subject to certain maximum amounts the maximum credits available will be determined by the Company's production level in 2008 and its drilling activity.

The new well incentive program will apply to wells commencing production of conventional oil or natural gas between April 1, 2009 and March 31, 2011 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels of crude oil or 500 Mmcf of natural gas.

Operating Expenses

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2009	2008	2009	2008
	\$	\$	\$	\$
Operating expenses	958,498	959,553	2,177,338	2,279,416
\$/boe (6:1)	12.30	10.79	8.65	9.64

Operating expenses include activities in the field required to operate wells and facilities, lift to surface, gather, process, treat and store production. For the third quarter of 2009, operating expenses were \$958,498 or \$12.30 per boe compared to operating expenses of \$959,553 or \$10.79 per boe for the third quarter of 2008. The increase in operating expense per boe quarter over

quarter is due consistent fixed costs with lower average production. Year to date, operating costs were \$2,177,338 or \$8.65 per boe as compared to \$2,279,416 or \$9.64 per boe for the corresponding period in 2008. The reduction in the year over year operating costs per boe is due to relative constant dollars spent with higher production reported for the nine months ended September 30, 2009.

Transportation

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2009	2008	2009	2008
	\$	\$	\$	\$
Transportation	223,074	262,809	529,349	475,565
\$/boe (6:1)	2.86	2.95	2.10	2.01

Transportation costs for the three months ended September 30, 2009 amounted to \$223,074 or \$2.86 per boe compared \$262,809 or \$2.95 for the three months ended September 30, 2008. Transportation costs are directly associated with production, the decrease of 15% quarter over quarter reflects the decrease in sales volumes reported.

For the nine month period, transportation costs have increased by 11% to \$529,349 or \$2.10 per boe, due to the increase in volumes reported for the same periods.

Operating Netback

(\$/boe) (6:1)	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2009	2008	2009	2008
Petroleum and natural gas revenue	24.07	62.53	25.92	63.14
Royalties	(4.26)	10.45	2.38	11.95
Operating expenses	12.30	10.79	8.65	9.64
Transportation	2.86	2.95	2.10	2.01
Operating netback	13.17	38.34	12.79	39.54

The Company's operating netback per boe (defined as petroleum and natural gas revenue net of royalties, operating expenses and transportation all on a per boe basis) was \$13.17 per boe for the third quarter of 2009. This represents a 66% decrease from the third quarter of 2008. For the nine month period operating netback was \$12.79 per boe compared to \$39.54 per boe representing a reduction of 68%. The decrease in operating netback for both three and nine month periods was due to lower commodity, offset by lower royalties.

General and Administrative Expenses ("G&A")

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2009	2008	2009	2008
	\$	\$	\$	\$
Gross G&A expenses	473,427	546,638	1,779,997	4,113,611
Capitalized G&G expenses	(119,081)	-	(274,470)	(774,156)
Overhead recovery	(20,340)	-	(65,234)	(42,197)
General and Administrative Expenses	334,006	546,638	1,440,293	3,297,258
\$/boe (6:1)	4.29	6.14	5.72	13.94

General and administrative expenses ("G&A") net of capitalized geological and geophysical ("G&G") expenses and overhead recoveries for the third quarter of 2009 were \$334,006 or \$4.29 per boe compared to \$546,638 or \$6.14 per boe for the third

quarter of 2008. The decrease in net G&A expenses on a per boe basis from the third quarter of 2008 is largely due to the capitalized portion of G&A related to G&G activity. For the nine month period, net G&A expenses on a boe basis were \$5.72 per boe compared to \$13.94 per boe for the same period in 2008. G&A costs in 2008 included management severance and proxy solicitation associated with management changes of \$1.7 million.

At September 30, 2009, ISR had four full time employees and four full time consultants.

Stock-Based Compensation Expense

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2009	2008	2009	2008
	\$	\$	\$	\$
Stock-based compensation expense	188,533	65,241	278,000	159,897
\$/boe (6:1)	2.42	0.73	1.10	0.68

For the three months ended September 30, 2009, the Company recorded \$188,533 of stock-based compensation expense for stock options outstanding during the period as compared to \$65,241 for the third quarter of 2008. For the nine month period, stock-based compensation expense was \$278,000 compared to \$159,897 for the same period in 2008. The increase of stock-based compensation expense is the result of adjusting the amortization method of recording this expense from a straight-line to a graded vesting calculation, keeping the vesting period constant. The change in estimate better reflects the benefit received and the vesting of that option benefit. The graded vesting method recognizes a larger portion of expense in the first and second year of amortization and vesting. The impact of the change in estimate resulted in recognizing an additional \$140,000 of expense in the third quarter of 2009 and year to date 2009.

Depletion, Depreciation and Accretion

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2009	2008	2009	2008
	\$	\$	\$	\$
Depletion and depreciation	2,488,400	1,007,800	6,333,612	3,065,844
Accretion	44,945	355,063	136,859	394,783
Total	2,533,345	1,362,863	6,470,471	3,460,627
Depletion and depreciation \$/boe (6:1)	31.93	11.33	25.16	12.97
Accretion \$/boe (6:1)	0.58	3.99	0.54	1.67
	32.51	15.32	25.70	14.64
Provision for international asset obligation (\$)	903,233	-	1,857,297	5,089,843

Depletion and depreciation of property and equipment are calculated based upon capital expenditures, production rates and reserves. The Company excludes unproved property costs, seismic and salvage values in its calculation of depletion and depreciation, but includes future development costs in the capital base. Accretion of asset retirement obligations is included in the depletion, depreciation and accretion expense ("DD&A").

The Company recorded \$2,533,345 or \$32.51 per boe of DD&A in the third quarter of 2009 compared to \$1,362,863 or \$15.32 per boe in the third quarter of 2008. Year to date, DD&A was \$6,470,471 or \$25.70 per boe compared to \$3,460,627 or \$14.64 per boe, reflective of higher production rates in 2009 and minimal impact on reserve additions in 2009.

The Company performed an impairment assessment in 2008 to assess the recoverable value of its international property and equipment, which are all in the preproduction stage. As a result of this assessment the Company recorded impairments against its petroleum and natural gas capitalized costs in Pakistan, Ecuador, Ghana, Colombia and Yemen, in total \$7,910,646. Accumulated provision for impairment on international projects at December 31, 2008 was \$10,317,310 (2007 - \$2,406,664).

Accretion

Accretion represents the change in the time value of asset retirement obligations ("ARO"). ARO is a balance sheet provision based on the Company's net ownership in wells and facilities. Management estimates the cost to abandon and reclaim the wells and facilities and the estimated time period during which these costs will be incurred in the future. Management estimates the total undiscounted amount of future cash flows required to abandon and reclaim wells and facilities as at September 30, 2009 to be approximately \$4.0 million to be incurred between 2010 and 2025. The Company used a discount rate of 7% to calculate its ARO obligations.

Underlying ARO may be increased over the period based on new obligations incurred from drilling wells or constructing facilities. Similarly, this obligation can be reduced as a result of abandonment work undertaken thereby reducing future obligations. There has been \$44,945 recognized as accretion expense for the third quarter of 2009 compared to \$355,063 for the third quarter of 2008.

Income Taxes

The Company has a future income tax liability recorded of \$544,613 at September 30, 2009. The Company has approximately \$21.0 million of tax pools available to be applied against future income for tax purposes. Based on available pools and current commodity prices, ISR does not expect to pay current income taxes in 2009. Taxes payable beyond 2009 will be a function of commodity prices, capital expenditures and production volumes.

Income taxes are comprised of two components: current and future income taxes. The expected 2009 income tax rate as a percentage of pre-tax income is 25%.

Capital Expenditures

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009 \$	2008 \$	2009 \$	2008 \$
Land	-	294,185	237,909	1,648,613
Geological and geophysical	129,330	71,687	690,515	103,958
Drilling and completion	590,875	632,753	2,160,169	2,055,943
Equipment, facilities and pipelines	65,387	144,838	130,781	464,071
Furniture and equipment	-	2,943	6,582	11,385
Total	785,592	1,146,406	3,225,956	4,283,970

ISR invested \$785,592 on exploration and development expenditures during the third quarter of 2009 compared to \$1,146,406 in the third quarter of 2008. Year to date, exploration and development expenditures were \$3,225,956 compared to \$4,283,970 for the same period in 2008. The Company drilled two wells in the first quarter with varied results, however, they were not considered to be commercially viable. In the second quarter, the Company drilled a step out well and encountered gas, however, this well too was considered not to be commercially viable. The significant reduction to capital expenditures year over year is due to the reduced funds from operations as a result of low commodity prices, the reduced availability of both debt and equity capital and management's effort to prudently manage balance sheet leverage.

Liquidity and Capital Resources

As at September 30, 2009 the Company had negative working capital \$4,078,141, including the current outstanding operating loan balance. Generally, ISR uses a combination of funds from operations, bank debt and equity issues to finance its capital expenditure program.

The Company has revolving line of credit to a maximum of \$10.0 million. The facility was renewed on September 30, 2009 and is subject to an annual review scheduled for April 1, 2010. The Company is covenanted to maintain a working capital ratio of 1:1, defined as current assets, including undrawn availability, to current liabilities. The operating loan bears interest at prime plus 1% and is secured by a demand debenture for a maximum of \$25.0 million providing a floating charge over all assets of the Company and a letter of undertaking to encumber or dispose of assets, other than in the normal course of business without consent of the financial institution and to provide security under section 426 of the Bank Act and/or assign natural gas contracts. As at September 30, 2009, \$2,076,296 (December 31, 2008 – nil) was drawn against the revolving credit line, and letters of credit in the amount of \$7,500 and a performance guarantee bond for Sujawal block were held. The performance guarantee expired on November 8, 2009, however the Company considers it to be active and accrued for the liability.

As at September 30, 2009 and November 11, 2009, ISR had 16,096,084 voting common shares outstanding and 835,000 options to purchase common shares outstanding. The outstanding options have a weighted average exercise price of \$1.25 per share.

The oil and gas business is inherently risky and capital intensive and can require significant capital and cash resources to expand by growing reserves, production and cash flow. Given the nature of the oil and gas business, and the size of ISR, it must be able to continue to access capital markets to raise additional monies to grow.

The Company has budgeted approximately \$3.9 million in capital expenditures for balance of 2009 and expects to rely on internally generated cash flows and available lines of credit to fund its capital program. Currently the Company has unused capacity of approximately \$7.9 million on its operating loan

Contractual Obligations

As part of normal operations, the Company is party to various financial guarantees, letters of credit and other contractual commitments. Oil sales from Company production are contracted on a month-to-month evergreen basis and gas sales from Company production are contracted on an annual basis commencing each November. The Chief Executive Officer and the Chief Financial Officer are each party to a separate employment services agreement with the Company. The Company also has a letter of credit outstanding totaling \$7,500 to maintain its status as a licensed well operator in the province of British Columbia. The Company also has two performance guarantees \$334,703 (PKR 25.9) and \$482,490 (US\$450,000) which expired on July 20 and November 8, 2009, respectively. However, the Company considers both guarantees to be active and has accrued for the liability.

The Company also has a legal obligation to reclaim the lands on which it has production wells and/or facilities. These obligations come due at varying times, dependent upon when economic production ceases and the property is then available for abandonment and reclamation operations.

Obligations with a fixed term for the remainder of 2009 and the next two years are as follows:

	2009	2010	2011
Office lease base rent (Expiring August 2011)	\$ 35,613	\$ 142,452	\$ 94,968

Disclosure Controls and Procedures

The Company has established disclosure controls, procedures and policies so that the consolidated financial results are presented accurately, fairly and timely. The disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed or submitted under applicable securities regulation is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. All internal control systems, no matter how well designed, have inherent limitations. Therefore, these systems provide reasonable, but not absolute assurance, that financial information is accurate and complete.

Internal Controls Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and preparation of financial statements for external reporting purposes in accordance with Canadian GAAP. The Chief Executive Officer and Chief Financial Officer have designed internal controls over financial reporting or have caused them to be designed under their supervision to provide reasonable assurance regarding the reliability of financing reporting and the preparation of financial statement for external reporting purposes in accordance with Canadian GAAP.

Although management does not believe that any significant deficiencies exist in the Company's internal controls over financial reporting at September 30, 2009 that would result in a material misstatement of the Company's financial reporting, ISR continues to evaluate its processes and internal controls on an ongoing basis. There were no changes in internal control over financial reporting during 2009.

Business Risks

The oil and gas industry is subject to numerous risks, including commodity prices, interest rates, exchange fluctuations, as well as environmental concerns and the success of future drilling. ISR attempts to reduce and manage those risks that are controllable.

Safety and Environmental

Safety and environmental concerns are addressed through a corporate contingency plan and by continued emphasis on complying with environmental regulations.

Critical Accounting Estimates

The preparation of financial statements in accordance with GAAP requires management to make certain judgments and estimates. Due to timing of when activities occur compared to the reporting of those activities, management estimate and accrue operating results and capital spending. Changes in these judgments and estimates could have a material impact on the Company's financial results and financial condition.

The CICA Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of the plan, accounting standards in Canada for public companies are expected to converge with International Financial Reporting Standards ("IFRS") by the start of 2011. The Company is in the process of:

- Developing a plan to assess the impact of convergence of Canadian GAAP and IFRS;
- Identifying appropriate training;
- Identifying the relevant systems upgrade requirements; and
- Implementation timetable to commence dual reporting for 2010 ensuring the Company's ability to report under IFRS in 2011.

The table below outlines the Company's approach to implementing IFRS.

Activity	Action plan
Financial Statement preparation:	
Phase 1 Identify differences in Canadian GAAP and IFRS accounting policies	Document the differences
Phase 2 Identify IFRS accounting policies for ISR	Executive management sign off on all key IFRS accounting policies
Phase 3 Develop financial statements based on IFRS Quantify effects of change in initial IFRS disclosure and 2010 financial statements	Develop draft financial statement format
Education	
Define and introduce appropriate level of IFRS expertise for the following groups: Accounting and financial reporting Executive management Audit Committee Board of Directors	Controller and CFO to attend industry specific training Identify appropriate level of information for management, and directors of the Company.
Management Information Systems	
Review all business processes and systems are IFRS compliant Software changes and upgrades Systems for gathering data for IFRS disclosure	Systems upgrade will be available by fall of 2009
Control Environment	
For all accounting policies identified assess the implication and effectiveness of internal controls	All key controls, design and effectiveness to be assessed in conjunction with identifying the differences and accounting policies adopted.

The Company has commenced and completed Phase 1 of the project during the quarter and has commenced Phase 2.

Depletion

The Company accounts for oil and gas properties using the full-cost method of accounting. Under this method, depletion and restoration expenses are recorded using the unit-of-production method. All costs related to exploration and development of oil and gas reserves are capitalized on a country-by-country basis. Such costs include lease acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling productive and non-productive wells and overhead charges related directly to acquisition, exploration and development activities.

Depletion is an estimate of the reduction in recoverable costs of oil and gas properties during the year, matched against the related income. It is based on reserve estimates, which are evaluated by an independent third party. The determination of the quality and quantity recoverable reserves is also an area of risk. Oil and gas reserves are integral to assessing expected future financial performance, preparing financial statements and making investment decisions. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves, including many factors beyond the Company's control. The reserves used in calculating depletion and impairment of capital assets represents estimates only.

The Company mitigates this risk by having the reserves evaluation performed by a reputable third party consultant. The Company's Reserves Committee of the Board of Directors reviews the work and independence of this firm.

Costs of acquiring and evaluating unproven properties in Canada and costs of exploration and land in international cost centers are initially excluded from costs subject to depletion, until it is determined whether or not proved reserves are attributable to the properties or, in the case of major development projects, commercial production has commenced, or impairment has occurred. Impairment occurs whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. When

proven reserves are determined or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to the costs subject to depletion for that country's cost center. Proceeds from disposal of properties will normally be applied as a reduction of the cost of the remaining assets unless the disposal represents a significant disposition of reserves, in which case a gain or loss will be recorded.

Future Income Taxes

The Company accounts for future income taxes using the liability method. Future income tax assets and liabilities are measured based upon temporary differences between the carrying values of assets and liabilities and their tax bases. Future income tax expense is computed based on the change during the year in the future tax assets and liabilities. Future income tax expense is computed based on the change during the year in the future tax assets and liabilities. Future income tax assets or liabilities are calculated using tax rates anticipated to apply in the periods that the temporary tax differences are expected to reverse, effects of changes in tax laws, and tax rates are recognized when enacted. For the three month period ended September 30, 2009 this future income tax recovery was calculated to be \$755,692 compared to a tax expense of \$267,461 at the end of the corresponding period in 2008.

The process of estimating reserves is critical to several accounting estimates. It required significant judgments based on available geological, geophysical, engineering and economic data. These estimates may change substantially as data from ongoing development and production activities becomes available, and as economic conditions impacting oil and gas prices, operating costs and royalty burdens change. Reserve estimates impact net income through depletion, the determination of asset retirement obligations and the application of an impairment test. Revisions or changes in the reserve estimates can have either a positive or a negative impact on net income and the asset retirement obligation.

Where any disclosure of reserves data is made in this MD&A that does not reflect all reserves of the Company, it should be noted that the estimates of reserves and future net revenue for individual properties or groups of properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties. Any reference to "established reserves" has the meaning of the January 1, 2003, COGE (Canadian Oil and GAS Evaluation) Handbook, proved plus 50% of probable reserves, which is similar but not identical to the January 1, 2004 definition of proved plus probable reserves.

New accounting policies

Goodwill and Other Intangible Assets

On January 1 2009, the Company adopted the Section 3064 "Goodwill and Other Intangible Assets". The new section states that upon their initial identification, intangible assets are to be recognized as assets only if they meet the definition of an intangible asset and the recognition criteria. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. As for subsequent measurement of intangible assets, goodwill and disclosure, Section 3064 carries forward the requirements of the old Section 3062 "Goodwill and Other Intangible Assets". The adoption of this guideline does not have any material effect on the Company's consolidated financial statements.

In May 2009, the Canadian Institute of Chartered Accountants amended Section 3862 – "Financial Instruments-Disclosures", to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three-level hierarchy that reflects the significance of the inputs used in making the fair value measurements. These amendments will be effective for the Company's interim and annual financial statements beginning December 31, 2009.

In January 2009, the CICA issued EIC-173- "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities" which requires the Corporation to consider its own credit risk as well as the credit risk of its counterparty when determining the fair value of financial assets and liabilities, including derivative instruments. The accounting treatments provided in EIC-173 have been applied in the preparation of these financial statements and as required have been applied retrospectively without restatement of prior periods. The adoption of this standard did not have an impact on the financial statements.

Outlook

The Company's performance to date in 2009 has been adversely affected by the drastic decline in energy prices from the 2008 levels. Although prices seem to be recovering, the Company will adjust its strategy in order to be better equipped to handle the future volatility of specifically the natural gas market. The Company plans to accomplish this through both merger/acquisition possibilities combined with rebalancing the production portfolio more towards a 50:50 oil to gas ratio. Through such a program, the Company will increase production, revenue and profit streams and be able to generate the funds to fund further acquisitions as those become available.

Natural gas prices continued to decline in the third quarter of 2009 to \$2.78/mcf from the highs reached at \$9.69/mcf in the second quarter of 2008. While partially influenced by the strength of crude oil price changes, natural gas price changes are predominantly based on supply and demand fundamentals in the North American market.

Crude oil prices experienced a significant drop from the peak in mid July for West Texas Intermediate (WTI) of more than US\$145.00 per barrel to a range of between US\$60.00 to \$70.00 per barrel in late October. For the three months ended September 30, 2009, WTI averaged \$71.71 per barrel.

The Company will continue to review its capital expenditure program in light of the current economic climate. Since the present portfolio is approximately 90% gas, the Company will focus on opportunities that increase the oil component because we feel that the present outlook for near term gas prices versus oil prices is less favorable.

Hedging

The Company is prepared to participate in such a program at the appropriate price point; however given the size of the Company it must recognize the risk inherent in prices moving against any hedge in this market of volatile gas prices.

Domestic

With the focus of the Company shifting towards oil opportunities, the Company plans to drill a potential oil well during the fourth quarter of 2009. Pending the success of this well, the Company could potentially have three to four additional locations to further develop this area. As of the date of this MD&A, the Company was ready to spud a potential oil well when the Province of Alberta suspended issuance of all drilling permits concerning wells having a potential sour gas component pending review of all Energy Resources Conservation Board safety protocols, as the result of the order of the Alberta Court of Appeal. When this suspension will be lifted is uncertain. However, the Company will drill two shallow sweet gas wells as soon as freeze up permits.

The Company will also continue to explore for high production shallow gas with the drilling of two wells in Northern Alberta during the fourth quarter.

Strategic Direction

The Company realizes that although it presently possesses a relatively strong balance sheet, its sector is currently out of favour with the investing public and has and continues to explore avenues to increase shareholder value. Since the portfolio is heavily weighted towards gas we are captive to the North American economic recovery, which is presently subject to an overabundance of supply.

The Company is pursuing the drilling plans mentioned in the previous section in order to move its portfolio towards more oil, as well, continuing to explore the acquisition of oil bearing assets and increasing its portfolio of undeveloped land for future exploration and development in order to increase future reserves, production and cash flow so as to maximize shareholder value..

International

The international properties in Pakistan and Ecuador will receive appropriate attention so that the Company can best benefit from those significant investments.

Pakistan

The Company signed two farm-in agreements with Mari Gas Company (MGCL) of Pakistan, the second largest producer of gas in Pakistan. The Company's direct working interest (WI) in each block is fifteen percent (15%) with all the work and management performed by a local seasoned and well established gas producer. The farm-in agreement provides that the Company be responsible for 25% of the development costs of the three wells in the Sukkur field. This 2,416.43 sq. km. block is situated in Sindh Province (100 kms from Karachi), Southern Pakistan. The Block is situated next to the Badin area which contributes some 50% of Pakistan's hydrocarbon production. Numerous oil and gas discoveries exist to the East of the block. MCGL has completed the re-interpretation of vintage 2D seismic from which a Lower Goru sand lead has been identified.

The Sukkur Joint Venture (SJV) is comprised of MCGL, the operator, with a 50% WI, Petroleum Exploration Limited, a Pakistani exploration and production company with a 35% WI and the Company, as mentioned above, with a 15% WI, The SJV committed to drill 3 exploration wells in the Sukkur Exploration Block.

On May 27, 2009 the Company was informed by Mari Gas Company Limited ("MGCL"), the operator of the Sukkur Block with a 50% working interest ("WI"), and Sujawal Block with a 65% WI, that the Company was in default of non-payment of cash calls of its 15% WI in these Blocks if payment of all outstanding cash calls of approximately US\$1.2 million were not paid within 7 days. Under the Joint Operating Agreement ("JOA"), the Company has the right to remedy the default during a period of 60 days by making payment of all its share of the cash calls with interest at 3% over LIBOR or forfeit its WI. In the event of forfeiture, the Company will not be entitled to receive any consideration for such forfeited WI.

The Company had taken a provision of \$2.8 million in 2008 against international expenditures in Pakistan. The Company has provided for the capital expenditures and the cash calls relating to these Blocks. In addition the Company had posted performance bonds of \$334,703 (PKR 25,966,080) and \$482,490 (US\$450,000), and a potential liability of \$776,300 (US\$725,000), all of which have been provided for in the financial statements for the third and nine months ending September 30, 2009.

The Company is of the opinion that capital is presently better spent on its domestic drilling program that has substantially shorter payback periods. The Company has thus elected not to remedy the default, but to seek out parties that would take over its obligations. Although the Koonj Well, in the Sukkur Block, drilled in July 2008 has proven reserves, the operator has yet to start production despite assurances going back to November 2008. The Company is not confident that the production will commence in a timely manner, and the initial reserve estimates subsequent to drilling have been downgraded substantially.

On August 1, 2009 the Company was granted a temporary injunction until August 8th 2009 that stays MGCL and Petroleum Exploration (Pvt) Limited ("PEL") from forfeiture of the Company's WI in the Sukkur Block.

On September 2, 2009 the Company filed application for contempt of court and the court issued initial contempt notices to the Company's working interest partners in the Sukkur Block, who have ignored the injunction and have tried to forfeit the Company's working interest. The notices were successfully issued on September 4, 2009 with a hearing date set for September 9, 2009, which has now been adjourned to October 31, 2009 adjourned again to November 5, 2009 and further adjourned to November 23, 2009.

On October 3, 2009 the Company was granted a temporary injunction until October 5, 2009, subsequently adjourned to October 31, 2009, that stays MGCL from seeking forfeiture of the Company's WI in the Sujawal Block. The date now fixed for arguments on the injunction application for Sukkur Block and for written statement of MGCL in Sujawal Block was November 5, 2009 and now adjourned to November 23, 2009.

Ecuador

Management continues to review this investment with a view to determine if it fits the Company's risk profile. The Charapa Concession is currently being analyzed in detail and a work plan has been developed, in conjunction with the local authorities, to identify the method to achieve the maximum returns for both the Company and for Ecuador. This project is 100% owned by the Company and, as such, the Company is responsible for 100% of the costs and the attendant risks with, what is in effect, an under developed property. All environmental permits have been received. The Company continues to examine whether or not continuation of this investment is financially viable given that its banking covenants only allow cash flow from domestic operations to fund international operations.

On September 29, 2009 the Company received a deposit of US\$100,000 in escrow thereby accepting a non-binding letter of intent to sell its interest in the Charapa Marginal Oil Field ("Charapa") in Ecuador. Subject to due diligence and negotiation of a definitive agreement, the consideration for the purchase of Charapa includes US\$3.0 million and replacement of the Company's performance guarantee of US\$2.34 million to Petroecuador. On October 15, 2009 the Company granted an extension to October 30, 2009 to the potential purchaser of its interest in Charapa to complete its due diligence and then move to a definitive agreement.

On October 31, 2009 the Company executed a Memorandum of Understanding to sell its oil and gas interests in Ecuador to the same potential purchaser noted above and finalize a Purchase and Sale Agreement with a scheduled closing date on or before November 30, 2009.

Quarterly Financial Summary

	2009			2008				2007
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
	\$	\$	\$	\$	\$	\$	\$	\$
Petroleum and natural gas sales	1,874,929	2,108,350	2,544,921	3,540,511	5,563,108	5,389,527	3,977,498	2,507,172
Royalties	331,532	(411,928)	(517,853)	(1,148,280)	(929,812)	(1,074,952)	(821,277)	(532,693)
Operating expenses ⁽¹⁾	(1,181,572)	(579,181)	(786,713)	(533,086)	(1,222,362)	(758,516)	(774,104)	(798,684)
Operating netback (per boe)	13	11	4	19	38	46	34	20
Funds from (used in) operations ⁽²⁾	(292,180)	(1,084,520)	506,550	951,257	2,844,260	1,234,168	1,910,454	717,187
Per share – basic	(0.02)	(0.07)	0.03	0.07	0.20	0.09	0.14	0.05
Per share – diluted	(0.02)	(0.07)	0.03	0.07	0.18	0.09	0.14	0.05
Net earnings (loss)	(2,192,399)	(1,931,259)	(1,105,313)	(1,659,078)	1,149,936	(3,779,982)	489,464	(92,484)
Per share – basic	(0.14)	(0.12)	(0.07)	(0.12)	0.08	(0.27)	0.04	(0.01)
Per share – diluted	(0.14)	(0.12)	(0.07)	(0.12)	0.07	(0.27)	0.04	(0.01)
Capital expenditures	785,592	194,027	2,246,339	3,687,993	1,146,406	1,099,303	2,038,260	1,675,893

(1) Operating expenses include transportation costs.

(2) For the purpose of cash flow per share calculations, cash flow is defined as "funds from operations" before the changes in non-cash working capital. This definition is not a recognized measure under Canadian generally accepted accounting principles and accordingly may not be comparable to measure used by other companies.