

2011 Third Quarter Report

For the Nine Months Ended September 30, 2011

 WHERE
WE'RE
GOING

 WHERE
WE
STARTED

 WHERE
WE ARE

TSX: RE

CORPORATE SUMMARY

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010 ²	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010 ²
Crude oil and natural gas revenue ('000)	\$ 13,928	\$ 15,497	\$ 47,189	\$ 47,622
Funds from operations ('000) ¹	\$ 3,993	\$ 6,506	\$ 12,461	\$ 19,752
Per share - basic	\$ 0.10	\$ 0.21	\$ 0.35	\$ 0.64
- diluted	\$ 0.10	\$ 0.21	\$ 0.34	\$ 0.62
Net income (loss) ('000)	\$ 459	\$ 873	\$ (1,927)	\$ 3,002
Per share - basic	\$ 0.01	\$ 0.03	\$ (0.05)	\$ 0.10
- diluted	\$ 0.01	\$ 0.03	\$ (0.05)	\$ 0.10
Capital expenditures, net ('000)	\$ 15,089	\$ 9,320	\$ 44,389	\$ 30,173

	As at September 30, 2011	As at September 30, 2010
Working capital deficiency including bank debt ('000)	\$ 31,939	\$ 35,935
Common shares outstanding	38,786,315	30,837,079
Options outstanding	2,551,094	2,089,828

OPERATIONS	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Average daily production				
Crude oil and natural gas liquids (bbbl/d)	2,094	2,453	2,331	2,385
Natural gas (mcf/d)	4,608	7,715	4,998	7,663
Total (boe/d)	2,862	3,739	3,164	3,662
Average product prices				
Crude oil and natural gas liquids (Cdn\$/bbl)	\$ 63.68	\$ 56.74	\$ 65.59	\$ 59.21
Natural gas (Cdn \$/mcf)	\$ 3.92	\$ 3.79	\$ 4.00	\$ 4.33
Combined (Cdn\$/boe)	\$ 52.90	\$ 45.05	\$ 54.63	\$ 47.63
Field netback (Cdn\$/boe) ¹	\$ 20.71	\$ 22.33	\$ 20.68	\$ 23.84

Note ¹ Funds from operations, funds from operations per share and field netback are not terms prescribed by IFRS or the previous Canadian generally accepted accounting principles (Canadian GAAP), so are considered non-GAAP measures. Funds from operations represents cash generated from operating activities before changes in non-cash working capital and decommissioning expenditures. Rock considers funds from operations a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future growth through capital investment. Funds from operations per share is calculated using the same share basis which is used in the determination of net income (loss) per share. Field netback is calculated as crude oil and natural gas revenues after deducting royalties, operating costs and transportation costs, resulting in an approximation of initial cash margin in the field on crude oil and natural gas production. Rock's use of these non GAAP measurements may not be comparable with the calculation of similar measures for other companies.

Note ² Net income (loss) for the three and nine months ended September 30, 2010 has been restated for the effect of adopting IFRS. Further information on the IFRS impacts is provided in the Change in Accounting Policies Section of this MD&A.

LETTER TO THE SHAREHOLDERS

During the third quarter of 2011, Rock was focused on reducing operating costs in its heavy oil area, while adding natural gas production from the Elmworth area. In addition, the Company further defined the extent of the resource base in Elmworth and initiated the first stages of the strategic alternatives review process.

The third quarter of 2011 was highlighted by the following:

- New production additions from the Company's first North Elmworth Montney horizontal well and its first South Elmworth vertical well;
- Drilled eight (8.0 net) heavy oil wells;
- Increased the Company's undeveloped land position in Elmworth by 4,480 net acres adjacent to our recent successful initiatives;
- Acquired 3,200 net acres in a new heavy oil exploration area, in which the Company drilled a successful 100 percent working interest discovery well;
- Reduced the Company's operating costs by 17 percent to \$21.94 per boe in the third quarter of 2011 from \$26.37 per boe in the second quarter of 2011;
- Production averaged 2,862 boe per day (73 percent crude oil and natural gas liquids and 27 percent natural gas) that excluded approximately 400 boe per day of behind pipe production volumes. Current production is approximately 3,300 boe per day;
- Generated funds from operations for the third quarter of \$4.0 million (\$0.10/basic share);
- Completed an updated reserve report by the Company's external petroleum engineering consultants as at August 31, 2011 that established an increase in the Company's total proved and probable reserves to 21.5 million boe an increase of 35 percent since December 31, 2010.

Rock's daily production for the nine months of 2011 averaged 3,164 boe per day as it was adversely affected by performance issues on certain heavy oil wells, by the shutdown of the SemCAMS K3 plant and lost production from a Saxon well in the second quarter of 2011. Normal operations at the SemCAMS K3 plant resumed in the latter part of the second quarter of 2011 but were shut down again from October 11, 2011 to October 28, 2011. The plant is now back on-stream. Rock's heavy oil performance issues have been addressed and with the new production additions from the Elmworth wells, total production is currently estimated to be approximately 3,300 boe per day including approximately 1,900 barrels per day of heavy oil.

Financially, Rock generated funds from operations of \$4.0 million (\$0.10 per basic share) in the third quarter of 2011 the same as reported for the second quarter of 2011.

Rock's realized price in the third quarter of 2011 was \$52.90 per boe compared to \$59.99 per boe in the second quarter of 2011 primarily attributable to decreased crude oil prices. Rock generated a field netback of \$20.71 per boe in the third quarter of 2011 compared to \$21.37 per boe in the second quarter of 2011. Field netbacks for the third quarter of 2011 were impacted by the decrease in commodity prices partially offset by improved operating costs per boe. The Company was successful in reducing heavy oil field operating costs to \$25.55 per barrel in the third quarter of 2011 from \$32.75 per barrel in the second quarter of 2011. As a result of several initiatives implemented in the latter part of the second quarter of 2011, Rock's total corporate operating costs per boe decreased 17 percent to \$21.94 per boe in the third quarter of 2011 compared to \$26.37 per boe in the second quarter of 2011.

Net capital expenditures for the third quarter of 2011 were \$15.1 million and total net debt at the end of the quarter was \$31.9 million against total bank credit lines of \$62.0 million.

Area Activity Update

To date in 2011, Rock has drilled 20 (20.0 net) heavy oil wells with an 85% success rate. At September 30, 2011, all successful heavy oil wells drilled were on production.

In addition, the Company has drilled 3 (2.5 net) natural gas wells to date in 2011, including a second 100 percent working interest Montney vertical test well (13-12-68-10W6M) at South Elmworth that was drilled and cased in April 2011. The test well encountered 23 metres of pay in the Montney B zone, 22 metres of pay in the Montney C zone and 6 metres of pay in the Halfway zone. This well has further confirmed the extension of Montney natural gas reserves (both B and C zones) on Rock's South Elmworth lands. The Montney B zone in this well was completed and tested in October of 2011 and produced at an initial gross raw rate of 3.0 mmcf per day and a final rate after three days of 0.8 mmcf per day plus approximately 15 bbls per mmcf of natural gas liquids.

Rock has tied-in its first North Elmworth 50 percent working interest Montney horizontal well (13-7-71-9W6M). This well was drilled in the first quarter of 2011 and was tested for three days at a final production rate of 7.7 mmcf per day plus more than 50

bbls of natural gas liquids per mcf of natural gas. This well came on production in mid September 2011 at a gross raw restricted rate of 2.7 mcf per day plus more than 50 bbls per mcf of natural gas liquids.

Rock's 100 percent working interest Montney vertical test well (6-6-69-9W6M) at South Elmworth was cased in December 2010 and encountered natural gas in the Halfway, Montney C and Montney B zones. In June 2011, the up-hole Halfway zone in this well was completed, fracture-stimulated and came on production in October, 2011 at a gross raw initial rate of 2.0 mcf per day.

In July 2011, Rock was successful in acquiring another 5 (5.0 net) sections of undeveloped land significantly adding to its existing 8 (6.0 net) sections of Montney lands in North Elmworth. The Company also acquired another 2 (2.0 net) sections in its Elmworth South area at the same land sale. Rock's total undeveloped Montney land position in Elmworth now stands at 70.5 (68.5 net) sections.

In addition to the acquisition of undeveloped land at Elmworth, Rock acquired 3,200 net acres of undeveloped land on a new heavy oil exploration area in Saskatchewan. A successful 100 percent working interest discovery well was drilled on the newly acquired lands and was completed and put on production in the fourth quarter of 2011. The success of the discovery well in this area is expected to provide a significant drilling program for 2012.

Review of Strategic Alternatives to Maximize Shareholder Value

As a key component to the strategic alternative process, Rock engaged GLJ Petroleum Consultants ("GLJ") to prepare an independent evaluation of the Corporation's reserves with an effective date of August 31, 2011. The independent evaluation of the Corporation's reserves by GLJ established an increase in the Company's total proved and probable reserves of 35 percent since December 31, 2010 to 21.5 million boe. In addition, Rock commissioned Independent Land Evaluations Inc. ("ILE") to assess the value of Rock's undeveloped land at August 31, 2011. With these independent evaluations complete, having taken into account all of Rock's 2011 production performance, 2011 drilling activity, August 31, 2011 estimated debt levels, and current shares outstanding, the Company estimates its net asset value as at August 31, 2011 on a proven plus probable basis to be \$5.88 per fully diluted share. On a proven plus probable reserves plus possible Elmworth Montney reserves basis the value increases by \$1.41 per fully diluted share. The best estimate of the value of contingent resources identified on a portion of Rock's lands in the Elmworth area represents a further addition of \$2.78 per fully diluted share.

By the last week of October, the Company and its financial advisor FirstEnergy Capital Corp. had completed a detailed Confidential Information Memorandum, opened a data room for interested parties and commenced data room presentations. Rock does not intend to make further announcements regarding the process unless and until the Company's Board of Directors has approved a specific transaction or other course of action or otherwise deems disclosure of developments is appropriate.

Outlook

In order to fully understand and maximize the value of the Company while preserving production, cash flow, and a solid long term financial position, Rock's Board of Directors has approved capital spending for the fourth quarter of 2011 which will bring Rock's capital budget for 2011 to \$49 million. With anticipated cash flow from operations and planned capital spending in the fourth quarter of 2011, Rock anticipates that its total net debt at the end of the year will be approximately \$33 million against total bank credit lines of \$62 million.

Given the uncertainty of the nature and timing of the possible strategic alternatives, Rock will not provide updated guidance for 2012 at this time.

On behalf of the Board of Directors,

(Signed) "Allen J. Bey"
Chief Executive Officer

(Signed) "John H. Van de Pol"
President and CFO

November 8th, 2011

MANAGEMENT'S DISCUSSION AND ANALYSIS

Rock Energy Inc. ("Rock" or the "Company") is a publicly traded energy company engaged in the exploration for and development and production of crude oil and natural gas in Western Canada. Rock initiated a strategic alternatives process in August 2011. The Special Committee of the Board of Directors has engaged FirstEnergy Capital Corp. as financial advisor to assist in the previously announced process to identify strategic alternatives for Rock in order to maximize shareholder value. Rock will be evaluating a range of strategic alternatives to maximize shareholder value and accelerate development of its large Montney resource base. These could include but are not limited to a corporate sale or merger, a sale of a significant portion of the Company's assets, a joint venture or other minor asset sales. A data room opened in late October and interested parties are now conducting reviews of the Company's assets. The Company expects to begin evaluating alternatives in late November.

Rock evaluates its performance based on funds from operations, field netbacks and finding and development costs. Funds from operations are a measure used by the Company to analyze operations, performance, leverage and liquidity. Field netback is a benchmark used in the oil and gas industry to measure the financial contribution of crude oil and natural gas operations following the deduction of royalties, transportation costs, and operating expenses. Finding and development costs are another benchmark used in the oil and gas industry to measure the capital costs incurred by the Company to find and bring reserves on-stream on a per-unit basis, providing insight into the relative efficiency of capital investments.

Rock faces competition in the oil and gas industry for resources, including technical personnel and third-party services and capital financing. The Company addresses these issues through recruitment and retention of personnel with the expertise to develop opportunities on existing lands and control operating and administrative cost structures. Rock also seeks to obtain the best price available based on the quality of its produced commodities.

The following discussion and analysis is dated November 8, 2011 and is management's assessment of Rock's historical financial and operating results, together with future prospects, and should be read in conjunction with Rock's first IFRS condensed interim consolidated financial statements for the period ended March 31, 2011 and 2010 and the unaudited Interim Consolidated Financial Statements for the period ended September 30, 2011 and 2010 as well as the audited consolidated financial statements for the year ended December 31, 2010.

Basis of Presentation

The Interim Consolidated Financial Statements and comparative information have been prepared in accordance with International Financial Reporting Standards ("IFRS"). The Company adopted IFRS on January 1, 2011 with a transition date of January 1, 2010. Previously, Rock prepared its Interim Consolidated Financial Statements in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP"). The Company has provided IFRS accounting policies and prepared reconciliations between Canadian GAAP and IFRS in Note 3 and 17 of its first Unaudited Condensed Interim Consolidated Financial Statements at March 31, 2011 and 2010 and in Note 3 and 16 of its Condensed Interim Consolidated Financial Statements for the three and nine months ended September 30, 2011. Further information on the IFRS impacts is provided in the Change in Accounting Policies Section of this MD&A.

Certain financial measures referred to in this discussion, such as funds from operations and funds from operations per share, are not prescribed by IFRS or the previously prescribed Canadian GAAP in Canada. Funds from operations is a key measure that demonstrates the ability to generate cash to fund expenditures. Funds from operations are calculated by taking cash provided by operations from the consolidated statement of cash flows and adding back changes in non-cash working capital and decommissioning expenditures. Funds from operations per share are calculated using the same methodology for determining net income (loss) per share. Rock's use of these non prescribed financial measures may not be comparable to similar measures presented by other companies. These financial measures are not intended to represent operating profits for the period nor should they be viewed as an alternative to cash provided by operating activities, net income (loss) or other measures of financial performance calculated in accordance with IFRS. The reconciliation between funds from operations and cash flow from operations for the three and nine months ended September 30, 2011 and 2010 is presented in the table below.

	Three Months Ended 09/30/11	Three Months Ended 09/30/10	Nine Months Ended 09/30/11	Nine Months Ended 09/30/10
('000)				
Cash provided by operations	\$ 4,515	\$ 11,403	\$ 12,070	\$ 23,173
Add (deduct):				
Changes in non-cash working capital	(615)	(4,986)	93	(3,629)
Decommissioning expenditures	93	89	298	208
Funds from operations	\$ 3,993	\$ 6,506	\$ 12,461	\$ 19,752

Management uses certain industry benchmarks such as field netback to analyze financial and operating performance. Field netback has been calculated by taking crude oil and natural gas revenues less royalties, operating costs and transportation costs, resulting in an approximation of initial cash margin in the field on crude oil and natural gas production. This benchmark does not have a standardized meaning prescribed by IFRS and may not be comparable to similar measures presented by other companies. Management considers field netback an important measure to demonstrate profitability relative to commodity prices.

All barrels of oil equivalent (“boe”) conversions in this report are derived by converting natural gas to crude oil in the ratio of six thousand cubic feet (“mcf”) of natural gas to one barrel (“bbl”) of crude oil. Certain financial values are presented on a boe basis and such measurements may not be consistent with those used by other companies. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of six mcf to one boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Certain statements and information contained in this document, including but not limited to management’s assessment of Rock’s plans and future operations, production, reserves, revenue, commodity prices, operating and administrative expenditures, interest expense, future income taxes, drilling plans, acquisitions and dispositions, funds from operations, capital expenditure programs and debt levels, contain forward-looking statements. All statements other than statements of historical fact may be forward-looking statements. These statements, by their nature, are subject to numerous risks and uncertainties, some of which are beyond Rock’s control including the effect of general economic conditions, industry conditions, regulatory and taxation regimes, volatility of commodity prices, currency fluctuations, the availability of services, imprecision of reserve estimates, geological, technical, drilling and processing problems, environmental risks, weather, the lack of availability of qualified personnel or management, stock market volatility, the ability to access sufficient capital from internal and external sources and competition from other industry participants for, among other things, capital, services, acquisitions of reserves, undeveloped lands and skilled personnel, any of which may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such forward-looking statements, although considered reasonable by management at the time of preparation, may prove to be incorrect and actual results may differ materially from those anticipated in the statements made and, therefore, should not unduly be relied on. These statements speak only as of the date of this document. Rock does not intend and does not assume any obligation to update these forward-looking statements, whether as a result of new information, future events or otherwise, except as required by applicable law.

All financial amounts are in thousands of Canadian dollars (Cdn\$) unless otherwise noted.

Production

Production by Product	Three	Three	Change	Nine	Nine	Change
	Months	Months		Months	Months	
	Ended	Ended		Ended	Ended	
	09/30/11	09/30/10		09/30/11	09/30/10	
Heavy oil (bbls/d)	1,875	2,155	(13)%	2,107	2,076	1%
Light oil (bbls/d)	80	113	(29)%	79	107	(26)%
Natural gas (mcf/d)	4,608	7,715	(40)%	4,998	7,663	(35)%
Natural gas liquids (bbls/d)	139	185	(25)%	145	202	(28)%
Total boe/d (6:1)	2,862	3,739	(23)%	3,164	3,662	(14)%

Production for the three and nine months ended September 30, 2011 has decreased 23 and 14 percent, respectively over the same periods last year. During the three and nine months ended September 30, 2011, natural gas and liquids production was adversely affected by a significant mechanical failure at the SemCAMS K3 gas plant and gathering system which occurred in the first half of 2011, sale of natural gas properties in the first quarter of 2011 and normal production declines. The current year production was impacted by well performance issues from a Saxon well that was drilled in the first quarter of 2011 and the delay in the ties of its Elmworth Montney horizontal well (13-7-71-9W6M) and the Elmworth Montney vertical test well (6-6-69-9W6M). Subsequent to quarter end, both Elmworth wells were on production.

Heavy oil production in the third quarter of 2011 decreased by 13 percent compared to the third quarter of 2010 as a result of continued performance issues on a number of heavy oil wells, however, current heavy oil production exceeds 1,900 boe per day as the Company has addressed the performance issues. For the nine months of 2011, heavy oil production increased as a result of the 2010 heavy oil drilling program in the Plains area and the acquisition of heavy oil assets in the first quarter of 2011.

Product Prices

	Three	Three	Change	Nine	Nine	Change
	Months	Months		Months	Months	
	Ended	Ended		Ended	Ended	
	09/30/11	09/30/10		09/30/11	09/30/10	
Realized product prices						
Heavy oil (\$/bbl)	62.54	56.79	10%	64.74	58.92	10%
Light oil (\$/bbl)	85.50	66.09	29%	89.28	72.54	23%
Natural gas (\$/mcf)	3.92	3.79	3%	4.00	4.33	(8)%
Natural gas liquids (\$/bbl)	66.48	50.43	32%	64.94	55.12	18%
Combine average (\$/boe)	52.90	45.05	17%	54.63	47.63	15%
Cdn\$/US\$ exchange rate	1.020	0.962	6%	1.023	0.965	6%
Average reference prices						
Crude oil - WTI Cushing, Oklahoma (US\$/bbl)	89.75	76.14	18%	95.45	77.63	23%
Crude oil - Edmonton light (Cdn\$/bbl)	91.74	74.44	23%	94.35	76.56	23%
Heavy oil - Western Canadian Select ("WCS") (Cdn\$/bbl)	70.63	62.91	12%	74.34	67.02	11%
Natural gas - Henry Hub Daily Spot (US\$/mmbtu)	4.12	4.30	(4)%	4.23	4.59	(8)%
Natural gas - AECO C Daily Spot (Cdn\$/mcf)	3.72	3.55	5%	3.74	4.13	(9)%
Differentials						
Realized heavy oil price to Edmonton light	32%	24%	33%	31%	23%	35%
Realized heavy oil price to WCS	11%	10%	10%	13%	12%	8%

Crude oil and natural gas liquid commodity prices strengthened considerably during the three and nine months ended September 30, 2011 compared to the same periods in 2010. Average heavy oil prices of \$70.63 per boe for the third quarter of 2011 were 12 percent higher compared to the same quarter of 2010. Corporate heavy oil prices in the third quarter of 2011 were \$62.54 per barrel compared to \$56.79 per barrel in 2010. WTI crude oil prices had strengthened in 2011, rising over US\$100/bbl, however with recent market conditions, WTI has dropped to a forecast of approximately US\$90.00/bbl for the fourth quarter of 2011. Heavy oil differentials decreased in September 2011 in anticipation of increased heavy oil demand for the fourth quarter of 2011.

Natural gas prices for the third quarter of 2011 are approximately \$3.92 per mcf which is 3 percent above the comparable quarter of 2010. For the nine months ended September 30, 2011, AECO reference prices and realized natural gas prices have declined 8

percent compared to the same period of 2010 which was influenced by the drop in natural gas prices for August and September 2011.

Rock initiated a commodity price management program, effective January 1, 2011. The Company executed crude oil collars on an average of 1,100 bbls per day for 2011 and an average of 400 bbls per day for 2012 both with a floor price of US\$80.00 per boe and a ceiling price of US\$96.80 per boe. In addition, the Company also executed crude oil collars on an average of 400 bbls per day for the first three months of 2012 at a floor price of US\$92.60 per boe with a ceiling price of US\$109.60 and an average of 300 bbls per day for the first three months of 2013 at a floor price of US\$90.00 per boe with a ceiling price of US\$106.85. Subsequent to quarter end, the Company monetized its 2012 and 2013 crude oil collars and realized \$1,691 in proceeds.

Revenue

	Three Months Ended		Change	Nine Months Ended		Change
	09/30/11	09/30/10		09/30/11	09/30/10	
Crude oil and natural gas	\$ 13,928	\$ 15,497	(10)%	\$ 47,189	\$ 47,622	(1)%

The Company's revenue is primarily derived from crude oil and natural gas operations. Crude oil and natural gas revenue decreased by 10 and one percent in the three and nine months ended September 30, 2011 compared to the same period of 2010. The decrease in revenue in the third quarter is the result of a 23 percent decrease in production, offset by a 17 percent increase in realized product prices for the third quarter of 2011. Similarly, crude oil and natural gas revenue for the nine months ended September 30, 2011 was impacted by increased commodity prices and decreased production.

Royalties

	Three Months Ended		Change	Nine Months Ended		Change
	09/30/11	09/30/10		09/30/11	09/30/10	
Royalties	\$ 2,699	\$ 2,317	16%	\$ 9,153	\$ 7,368	24%
As a percentage of crude oil and natural gas revenue	19.4%	15.0%	29%	19.4%	15.5%	25%
Per boe (6:1)	\$ 10.25	\$ 6.74	52%	\$ 10.60	\$ 7.37	44%

Royalties for the three and nine months ended September 30, 2011 are higher on an absolute, percentage of revenue and per boe basis in comparison to the same periods of 2010 as a result of increased prices, a non-recurring gas cost allowance recovery received in 2010 and a reduced amount of production receiving lower royalty rates from the Alberta Government royalty incentive program. The Alberta Government has extended the royalty incentive program to 2018 on new well production. On a percentage basis royalty rates were 19.4 percent of crude oil and natural gas revenue for the three and nine months ended September 30, 2011 compared to 15.0 percent for the three months ended September 30, 2010 and 15.5 percent for the nine months ended September 30, 2010.

Operating Expense

	Three Months Ended		Change	Nine Months Ended		Change
	09/30/11	09/30/10		09/30/11	09/30/10	
Operating costs	\$ 5,723	\$ 5,342	7%	\$ 19,942	\$ 15,975	25%
Transportation costs	54	154	(65)%	233	441	(47)%
	5,777	5,496	5%	20,175	16,416	23%
Per boe (6:1)	\$ 21.94	\$ 15.98	37%	\$ 23.36	\$ 16.42	42%

Operating expenses have increased on an absolute and boe basis during the three and nine months ended September 30, 2011 over the same periods in 2010 primarily due to an increase in well servicing activity, fuel costs and crude oil and water handling costs on heavy oil wells. With lower production, operating expense per boe is dramatically higher compared to previous periods.

The Company is focused on initiatives targeted to reduce its operating expenses and has seen a decrease in operating expenses during the third quarter of 2011. These initiatives include shutting in heavy oil wells that are incurring high operating costs on minimal heavy oil production, fuel gas initiatives to convert fuel usage to lower cost natural gas from propane, initiating water disposal facilities and anticipated reductions in workovers and product handling costs.

Exploration and Evaluation Expense

	Three Months Ended			Nine Months Ended		
	09/30/11	09/30/10	Change	09/30/11	09/30/10	Change
Exploration and evaluation	\$ 358	\$ 22	1527%	\$ 690	\$ 770	(10)%
Per boe (6:1)	\$ 1.36	\$ 0.06	2167%	\$ 0.80	\$ 0.77	4%

The Company's exploration and evaluation expense represents all pre-license costs and the capitalized costs from exploration and evaluation assets that have been subsequently expensed. These costs represent unrecoverable exploration and evaluation costs associated with an area and costs incurred prior to obtaining the legal rights to explore. During the three and nine month period ended September 30, 2011, \$358 and \$690 of book value for land expiries were expensed during the quarter.

General and Administrative (G&A) Expense

	Three Months Ended			Nine Months Ended		
	09/30/11	09/30/10	Change	09/30/11	09/30/10	Change
Gross	\$ 1,508	\$ 1,226	23%	\$ 5,026	\$ 4,534	11%
Per boe (6:1)	\$ 5.73	\$ 3.57	61%	\$ 5.82	\$ 4.54	28%
Capitalized	\$ 369	\$ 354	4%	\$ 1,406	\$ 1,203	17%
Per boe (6:1)	\$ 1.40	\$ 1.03	36%	\$ 1.63	\$ 1.20	36%
Net	\$ 1,139	\$ 872	31%	\$ 3,620	\$ 3,331	9%
Per boe (6:1)	\$ 4.33	\$ 2.53	71%	\$ 4.19	\$ 3.33	26%
Share based payments (net)	\$ 260	\$ 275	(5)%	\$ 871	\$ 580	50%
Per boe (6:1)	\$ 0.99	\$ 0.80	24%	\$ 1.01	\$ 0.58	74%
Total G&A	\$ 1,399	\$ 1,147	22%	\$ 4,491	\$ 3,911	15%
Per boe (6:1)	\$ 5.31	\$ 3.33	59%	\$ 5.20	\$ 3.91	33%

Gross and net G&A expenses increased on an absolute and per boe basis in the third quarter of 2011 compared to the same period in 2010. This increase is primarily due to higher rent costs as a result of terminating the Company's sublease, increased staff levels and one-time severance costs incurred in the third quarter of 2011. This increase is offset by lower G&A costs due to audit and consulting costs related to the Company's IFRS conversion. Overall costs for the nine months ended September 30, 2011 increased on an absolute and per boe basis compared to the same period of 2010 due to staffing increases and rent costs offset by lower audit and consulting costs related to its IFRS conversion. On a per boe basis, G&A expenses were higher in both periods of 2011 compared to 2010 due to the 2011 decrease in production. The Company capitalizes direct G&A expenses based on personnel involved in exploration and development activities.

Share based payment costs are non-cash charges which reflect the estimated value of stock options issued to directors and employees of Rock. The value of the award is recognized as an expense over the period from the grant date to the date of vesting of the award. The Company capitalizes a portion of share-based compensation expense related to personnel involved in exploration and development activities.

Finance Expense

	Three Months Ended			Three Months Ended			Nine Months Ended				
	09/30/11			09/30/10			09/30/11				
			Change			Change			Change		
Interest expense	\$	301		\$	306	(2)%	\$	955	\$	755	26%
Per boe (6:1)	\$	1.14		\$	0.89	28%	\$	1.11	\$	0.76	46%
Accretion expense	\$	53		\$	41	29%	\$	150	\$	123	22%
Per boe (6:1)	\$	0.20		\$	0.12	67%	\$	0.17	\$	0.12	42%
Finance expense	\$	354		\$	347	2%	\$	1,105	\$	878	26%
Per boe (6:1)	\$	1.34		\$	1.01	33%	\$	1.28	\$	0.88	45%

Interest incurred is a result of bank borrowings. Interest expense has decreased in the third quarter of 2011 compared to the same period in 2010 due to lower bank borrowings offset by higher interest rates. For the nine months ended interest expense increased by 26 percent compared to the same period in 2010. The average effective interest rate on debt for the nine months ended September 30, 2011 was 3.8 percent compared to 3.2 percent for the same period in 2010.

Accretion represents the change in the time value of the decommissioning liability. Accretion expense increased for the three and nine months ended September 30, 2011 compared to the same period of 2010 due to new obligations from wells drilled and the acquisition of crude oil and natural gas assets offset by the disposition of crude oil and natural gas interests. The underlying liability may increase over a period based on new obligations incurred from drilling wells, constructing facilities, acquiring operations or adjusting future estimates of timing or amounts. Similarly this obligation can be reduced as a result of abandonment work undertaken and reducing future obligations.

Depletion and Depreciation

	Three Months Ended			Three Months Ended			Nine Months Ended				
	09/30/11			09/30/10			09/30/11				
			Change			Change			Change		
Depletion and depreciation expense	\$	6,623		\$	4,838	37%	\$	18,662	\$	14,047	33%
Per boe (6:1)	\$	25.15		\$	14.06	79%	\$	21.61	\$	14.05	54%

Depletion and depreciation expense is computed on a unit of production basis. Such expense, on a boe basis, fluctuates period to period primarily as a result of changes in the underlying proved and probable reserves base and in the amount of costs subject to depletion and depreciation. Such costs are segregated and depleted on an area by area basis relative to their respective underlying proved and probable reserves base. The depletion and depreciation expense for the three and nine months ended September 30, 2011 was higher on both an absolute basis and a boe basis than in the same periods of 2010. The increase is the result of higher capital and future development costs subject to depletion and significant decreases to the proved and probable reserves base for the Neilburg and Lloyd heavy oil areas.

Impairment testing is performed at the cash-generating unit ("CGU") level and is a one-step process for testing and measuring impairment of assets where each CGU's carrying value is compared to the higher of value in use and fair value less costs to sell. Impairment testing is required when there are indicators of impairment such as a significant drop in commodity prices or a write-down of proved or probable reserves. During the three months ended June 30, 2011, Rock recognized a \$5,370 impairment relating to a CGU consisting of natural gas properties. The impairment was based on the difference between the period-end net book value of the assets and the recoverable amount determined using fair value less costs to sell based on discounted cash flows of proved and probable reserves using forecast prices and costs.

Taxes

Rock does not have current income tax payable and does not expect to pay current income taxes in 2011 as the Company has estimated resource tax pools available at September 30, 2011 of \$153.3 million.

Funds from Operations and Net Income (Loss)

	Three Months Ended			Three Months Ended			Nine Months Ended		
	09/30/11	09/30/10	Change	09/30/11	09/30/10	Change	09/30/11	09/30/10	Change
Funds from operations	\$ 3,993	\$ 6,506	(39)%	\$ 12,461	\$ 19,752	(37)%			
Per boe (6:1)	\$ 15.16	\$ 18.91	(20)%	\$ 14.43	\$ 19.76	(27)%			
Per share									
Basic	\$ 0.10	\$ 0.21	(52)%	\$ 0.35	\$ 0.64	(45)%			
Diluted	\$ 0.10	\$ 0.21	(52)%	\$ 0.34	\$ 0.62	(45)%			
Cash provided by operating activities	\$ 4,515	\$ 11,403	(60)%	\$ 12,070	\$ 23,173	(48)%			
Net income (loss)	\$ 459	\$ 873	(47)%	\$ (1,927)	\$ 3,002	(164)%			
Per boe (6:1)	\$ 1.74	\$ 2.54	(31)%	\$ (2.23)	\$ 3.00	(174)%			
Per share									
Basic	\$ 0.01	\$ 0.03	(67)%	\$ (0.05)	\$ 0.10	(150)%			
Diluted	\$ 0.01	\$ 0.03	(67)%	\$ (0.05)	\$ 0.10	(150)%			
Weighted average shares outstanding:									
Basic	38,785,216	30,852,318	26%	35,717,746	30,656,682	17%			
Diluted	39,255,335	31,714,835	24%	36,354,547	31,682,206	15%			

Funds from operations in the third quarter and nine months ended September 30, 2011 decreased over the same periods in 2010 due to lower production and higher operating costs offset by increased commodity prices. Cash provided by operating activities decreased for the three and nine months ended September 30, 2011 compared to 2010 as a result of decreased production, higher operating costs and changes in non-cash working capital accounts.

The Company had net income of \$459 for the third quarter of 2011 primarily due to higher commodity prices and an unrealized gain on commodity price contracts of \$4.2 million, offset by lower production. For the nine months ended September 30, 2011, the Company incurred a net loss of \$1.9 million as a result of lower production, higher operating costs, an impairment loss of \$5.3 million offset by increased commodity prices and a gain on sale of property, plant and equipment of \$7.5 million.

Basic and diluted shares outstanding have increased due to the equity issue of 4,238,100 shares and 1,640,000 flow-through shares completed in May 2011, a flow-through equity issue of 1,855,000 shares completed in November 2010 and dilutive stock options.

Capital Expenditures

	Three Months Ended		Change	Nine Months Ended		Change
	09/30/11	09/30/10		09/30/11	09/30/10	
Drilling and completions	\$ 5,553	\$ 5,389	3%	\$ 18,495	\$ 20,304	(9)%
Facilities	2,536	615	312%	3,945	1,821	117%
Capitalized G&A	377	354	6%	1,307	1,203	9%
Capitalized share based payments	132	151	(13)%	368	320	15%
	\$ 8,598	\$ 6,509	32%	\$ 24,115	\$ 23,648	2%
Property acquisition	267	35	663%	13,246	1,786	642%
Property disposition	32	-	n/a	(11,755)	-	n/a
Office equipment	147	-	n/a	284	3	9367%
Total property, plant and equipment	\$ 9,044	\$ 6,544	38%	\$ 25,890	\$ 25,437	2%
Land	3,610	954	278%	6,253	1,425	339%
Seismic	98	27	263%	1,092	543	101%
Exploratory drilling and completions	2,341	1,795	30%	11,043	2,768	299%
Capitalized G&A	(8)	-	n/a	99	-	n/a
Capitalized share based payments	4	-	n/a	12	-	n/a
Total exploration and evaluation	\$ 6,045	\$ 2,776	118%	\$ 18,499	\$ 4,736	291%
Total net capital expenditures	\$ 15,089	\$ 9,320	62%	\$ 44,389	\$ 30,173	47%

Capital spending in the third quarter and nine months of 2011 was significantly higher than the same periods of 2010 due to increased exploration drilling activity and related facilities expenditures. Exploration and evaluation costs are area expenditures where technical feasibility and commercial viability has not yet been determined. These costs include undeveloped lands, geological and geophysical costs, exploration and evaluation drilling and completion costs. Costs incurred prior to acquiring the legal rights to explore are expensed as incurred. Exploration and evaluation expenditures increased as a result of exploratory drilling and completion and land purchased in the Company's Elmworth area. During the nine months ended September 30, 2011, the Company drilled one (0.5 net) horizontal Elmworth Montney well (13-7-71-9W6M) and one (1.0 net) vertical well in South Elmworth (13-12-68-10W6).

In addition to the exploratory drilling program, the Company drilled 17 (17.0 net) heavy oil wells in the Plains core area, one (1.0 net) natural gas well in the Saxon area and three (3.0 net) dry holes compared to 27 (27.0 net) heavy oil wells, one (1.0 net) dry holes and 5 (3.2 net) natural gas wells in the West Central Alberta area in the same period of 2010. As well, the Company incurred additional facility costs related to the tie-in of the Elmworth horizontal Montney well (13-7-71-9W6M) and the vertical well in South Elmworth (6-6-69-9W6M). During the nine months ended September 30, 2011, the Company also acquired heavy oil assets for \$13.3 million and disposed of certain non-core conventional oil and gas assets for net proceeds of \$11.8 million.

Liquidity and Capital Resources

In order to preserve a solid future for the Company, the Company's Board of Directors approved a capital budget for 2011 of \$49 million. The capital spending is in excess of funds from operations and, therefore, the Company raised equity in May 2011. The Company has a net debt position of \$31.9 million including a negative working capital position of \$1.1 million at September 30, 2011. The Company's total debt to third quarter 2011 annualized funds from operations ratio was 2.0 to 1. At September 30, 2011, the debt to annualized funds flow has temporarily exceeded the Company's desired level due to significant third quarter expenditures. The Company will continue to monitor capital, debt and expenditure levels and make adjustments in order to maintain an appropriate debt to funds from operations level.

During the nine months ended September 30, 2011, the Company closed an equity and flow-through financing of 4,238,100 common shares at a price of \$5.00 per share for gross proceeds of \$21.2 million and 1,640,000 common shares on a flow-through basis at \$6.10 per share for gross proceeds of \$10.0 million. The net proceeds were used to reduce drawings on the Company's bank credit facilities and provide capacity for its ongoing capital expenditure program and for general corporate purposes.

The Company has a demand operating loan facility with a Canadian chartered bank. The facility is subject to the bank's valuation of the Company's crude oil and natural gas assets. The facility bears interest at the bank's prime rate or at prevailing banker's acceptance rate plus an applicable bank fee, which varies depending on the Company's debt to funds from operations ratio. The facility also bears a standby charge for un-drawn amounts. The facility is secured by a first ranking floating charge on all real

property of the Company, its subsidiary and partnership and a general security agreement. A review was completed in October 2011 that established the available facility at \$62 million. The next review for the facility is scheduled to be completed by January, 2012.

Selected Quarterly Data (unaudited)

The following table provides selected quarterly information for Rock.

	Three Months Ended 09/30/11	Three Months Ended 06/30/11	Three Months Ended 03/31/11	Three Months Ended 12/31/10	Three Months Ended 09/30/10	Three Months Ended 06/30/10	Three Months Ended 03/31/10	Three Months Ended 12/31/09
Production (boe/d)	2,862	3,150	3,487	3,472	3,739	3,720	3,524	3,376
Crude oil and natural gas revenues (\$000)	\$ 13,928	\$ 17,199	\$ 16,062	\$ 15,732	\$ 15,497	\$ 15,285	\$ 16,840	\$ 14,597
Average realized price (\$/boe)	\$ 52.90	\$ 59.99	\$ 51.18	\$ 49.26	\$ 45.05	\$ 45.15	\$ 53.09	\$ 47.00
Royalties (\$/boe)	\$ 10.25	\$ 12.26	\$ 9.36	\$ 7.28	\$ 6.74	\$ 5.30	\$ 10.27	\$ 8.37
Operating expense (\$/boe)	\$ 21.94	\$ 26.37	\$ 21.79	\$ 18.71	\$ 15.98	\$ 16.91	\$ 16.38	\$ 14.49
Field netback (\$/boe) ²	\$ 20.71	\$ 21.37	\$ 20.03	\$ 23.27	\$ 22.33	\$ 22.94	\$ 26.44	\$ 24.14
G&A expense (\$/boe)	\$ 5.31	\$ 5.34	\$ 4.08	\$ 2.97	\$ 2.54	\$ 3.80	\$ 3.70	\$ 3.20
Interest expense (\$/boe)	\$ 1.14	\$ 1.13	\$ 1.05	\$ 0.91	\$ 0.89	\$ 0.75	\$ 0.62	\$ 0.70
Funds from operations (\$000) ¹	\$ 3,993	\$ 4,016	\$ 4,452	\$ 6,189	\$ 6,506	\$ 6,283	\$ 6,963	\$ 6,150
Per share								
Basic	\$ 0.10	\$ 0.11	\$ 0.14	\$ 0.19	\$ 0.21	\$ 0.21	\$ 0.23	\$ 0.21
Diluted	\$ 0.10	\$ 0.11	\$ 0.13	\$ 0.19	\$ 0.21	\$ 0.20	\$ 0.22	\$ 0.20
Net income (loss) (\$000) ³	\$ 459	\$ (3,106)	\$ 720	\$ (2,153)	\$ 873	\$ 850	\$ 1,279	\$ (556)
Per share								
Basic	\$ 0.01	\$ (0.09)	\$ 0.02	\$ (0.07)	\$ 0.03	\$ 0.03	\$ 0.04	\$ (0.02)
Diluted	\$ 0.01	\$ (0.09)	\$ 0.02	\$ (0.07)	\$ 0.03	\$ 0.03	\$ 0.04	\$ (0.02)
Capital expenditures	\$ 15,089	\$ 9,465	\$ 19,835	\$ 12,119	\$ 9,320	\$ 7,188	\$ 13,665	\$ 10,424
	As at 09/30/11	As at 06/30/11	As at 03/31/11	As at 12/31/10	As at 09/30/10	As at 06/30/10	As at 03/31/10	As at 12/31/09
Working capital deficiency (surplus) ⁴	\$ 1,117	\$ 1,196	\$ 3,468	\$ 7,806	\$ 495	\$ (2,069)	\$ 3,153	\$ 2,335

¹ Funds from operations is calculated as cash generated from operating activities before changes in non-cash working capital and decommissioning expenditures.

² Field netback is calculated as crude oil and natural gas revenues less royalties, operating costs and transportation costs.

³ Net income (loss) for comparative periods have been restated for the effect of adopting IFRS.

⁴ Working capital deficiency is calculated as current assets less current liabilities excluding bank debt.

⁵ Rock's IFRS transition date was January 1, 2010, therefore 2009 comparative information has not been restated.

Crude oil and natural gas production increased from December 31, 2009 to September 30, 2010 due to heavy oil drilling activity. During the fourth quarter of 2010, the Company experienced a reduction in its production due to excessive production downtime and reduced well performance related to cold weather conditions on its heavy oil operations. During the first quarter of 2011, crude oil and natural gas production remained relatively consistent with the fourth quarter of 2010. The Company experienced production downtime in the second quarter of 2011 due to continued performance issues on a number of heavy oil wells, by the shutdown of the SemCAMS K3 and from the loss of production from a Saxon well. During the third quarter of 2011, the Company continued to experience performance issues on a number of heavy oil wells with normal declines on natural gas production.

Prices and production began to increase during the first quarter of 2010 resulting in increased crude oil and natural gas revenue. For the second and third quarter of 2010, crude oil and natural gas revenue increased as a result of increased production, which was partially offset by a lower average realized natural gas price and lower realized heavy oil prices. For the fourth quarter of 2010 and the first and second quarters of 2011, revenues increased due to higher oil-based commodity prices. During the third quarter of 2011, revenues decreased due to lower production and commodity prices.

Royalties per boe averaged approximately 18 percent in the latter half of 2009 primarily due to lower commodity prices. Royalties were lower still for 2010, due to the Alberta royalty incentive program initiated in 2009 and a prior period gas cost allowance adjustment received in 2010 from the Alberta government. For the first and second quarters of 2011, royalties have increased due to higher commodity prices and a lesser impact of the Alberta royalty incentive program. For the third quarter of 2011, royalties have decreased on an absolute percentage of revenue and boe basis due to lower production and commodity prices.

Operating costs began to increase in the first three quarters of 2010 due to a change in the Company's product mix as heavy oil prices improved, heavy oil drilling increased and work-over costs associated with heavy oil wells were incurred. Fourth quarter 2010 operating costs increased due to production downtime in the quarter resulting in unusually high per-boe costs. During the first and second quarter of 2011, operating costs have increased due to additional production downtime and increased costs in well servicing, fuel costs, crude oil and water handling costs and work-over costs on its heavy oil wells. The Company experienced improvement in operating costs during the third quarter of 2011 as a result of cost cutting initiatives during the period.

G&A expenses for the first and second quarters of 2010 included bonus payments related to 2009 performance and one-time termination costs. Without incurring these one-time items, G&A expenses for the third quarter of 2010 returned to normal levels on a per-boe basis. Fourth quarter 2010 G&A expenses were higher due to costs associated with year-end reporting. In the first, second and third quarter of 2011, G&A expenses per boe are unusually high due to lower than anticipated production.

Funds from operations have varied primarily due to changes in commodity price levels and production levels. The first two quarters of 2011 were impacted by lower production, higher operating costs partially offset by increased commodity prices. The third quarter of 2011 was impacted by lower production and commodity prices. Management decided to reduce capital expenditures in the first three quarters of 2009 primarily due to an uncertain commodity price environment. For the fourth quarters of 2009 and throughout 2010, capital expenditures increased as the Company initiated an expanded heavy oil program due to an improvement in crude oil prices, heavy oil differentials and the introduction of the Alberta royalty incentive program. During the first quarter of 2011, the Company increased capital expenditures related to its exploratory drilling program in the Elmworth area and acquired heavy oil assets and disposed of certain non-core conventional oil and gas assets. Capital expenditures were lower in the second quarter of 2011 due to spring break up and unusual wet weather conditions. In the third quarter of 2011, the Company increased capital expenditures by drilling 6 (6.0 net) heavy oil wells, 2 (2.0 net) dry holes, Elmworth land purchases and increased facility expenditures in Elmworth.

Contractual Obligations

In the course of its business the Company enters into various contractual obligations including the following:

- Royalty agreements;
- Processing agreements;
- Right of way agreements; and
- Lease obligations for leased premises.

Obligations with a fixed term are as follows:

(\$000)	2011	2012
Office lease premises	\$ 218	\$ 581
Processing arrangements	\$ 52	\$ 159

Outstanding Share Data

At September 30, 2011 Rock had 38,786,315 common shares outstanding and 2,551,094 stock options outstanding with an average exercise price of \$3.83. At November 8, 2011 Rock has 38,786,315 common shares outstanding and 2,551,094 options to purchase common shares outstanding with an average exercise price of \$3.83.

Disclosure Controls and Procedures

Management reported on its disclosure controls and procedures and the design of its internal controls over financial reporting in the year end 2010 MD&A. There has been no material change to the Company's disclosure controls or procedures or to the design of internal controls over financial reporting since that time.

Change in Accounting Policies

Adoption of International Financial Reporting Standards

The Condensed Interim Consolidated Financial Statements and comparative information have been prepared in accordance with International Financial Reporting Standards ("IFRS"). The Company adopted IFRS on January 1, 2011. Previously, Rock prepared its Interim Consolidated Financial Statements in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP"). The Company has provided IFRS accounting policies and prepared reconciliations between Canadian GAAP and IFRS in Note 3 and 17 of its first Condensed Interim Consolidated Financial Statements as at March 31, 2011 and in Note 3 and 16 of its Condensed Interim Consolidated Financial Statements for the three and nine months ended September 30, 2011. Further information on the significant IFRS accounting policy changes are provided in the Change in Accounting Policies Section of this MD&A. The following provides summary reconciliations of Rock's 2010 net income under Canadian GAAP and IFRS to illustrate the impact on adoption. The adoption of IFRS did not have an impact on the Company's cash flows and capital expenditures.

Summary of Net Income

(\$000)	2010				
	Annual	Q4	Q3	Q2	Q1
Net income (loss) - Canadian GAAP	(3,627)	(2,300)	(779)	(601)	53
Addition/(deduction):					
Exploration and evaluation	(1,964)	(1,194)	(22)	(318)	(430)
General and administrative	22	(6)	12	13	2
Gain on sale of property, plant and equipment	546	546	-	-	-
Depletion and amortization	7,514	1,114	2,142	2,178	2,083
Finance expense (including accretion)	365	111	93	81	78
Deferred taxes	(2,007)	(424)	(573)	(503)	(507)
Net income (loss) - IFRS	849	(2,153)	873	850	1,279

Accounting Policy Changes

The following discussion illustrates the significant differences between Canadian GAAP and the accounting policies applied by the Company under IFRS. IFRS 1 *First-time adoption of International Financial Reporting Standards* allows first-time adopters certain exemptions from retrospective application of certain IFRS. IFRS policies have been retrospectively applied except where specific IFRS 1 optional and mandatory exemptions permitted an alternative treatment upon transition to IFRS.

IFRS 1 Exemptions

IFRS 1 contains exemptions whereby a Company may choose to apply IFRS to Property, Plant and Equipment ("PP&E") prospectively to its full cost pool provided a ceiling test under IFRS standards is conducted at the transition date. More specifically, a Company may choose to allocate the historical full cost pool to cost centres by utilizing either volume or values from current reserves at the transition date. The Company has elected to apply this optional exemption under IFRS 1 and has allocated the historical full cost pool to cash-generating units based on proved plus probable reserve values.

As part of the aforementioned exemption, the Company was able to re-measure its decommissioning liability as at the date of transition in accordance with IFRS and recognize directly into retained earnings any difference from the amount recorded under Canadian GAAP. The Company applied a lower risk-free discount rate to measure its decommissioning liability. As a result, the decommissioning liability balance increased by \$2.6 million (\$1.9 million after tax) under IFRS from Canadian GAAP.

The Company applied the optional exemptions in respect of business combinations and share-based payment transactions, both of which grant a first-time adopter relief from retrospective restatement in accordance with IFRS prior to the date of transition to IFRS.

The Company determined the total impact of the conversion to IFRS was a reduction in retained earnings on January 1, 2010 in the amount of \$2.8 million. The Company has performed ceiling test calculations at the transition date and did not have any transitional ceiling test write-downs associated with its petroleum and natural gas properties.

Exploration and Evaluation

Exploration and evaluation (“E&E”) are those expenditures for an area or project for which technical feasibility and commercial viability have not yet been determined. These costs include exploratory drilling and completion, costs of acquiring licenses and directly attributable general and administration costs. The Company capitalizes these costs as E&E assets. When technical feasibility and commercial viability are determined, the costs will be transferred to PP&E. At the date of transition, \$20.8 million were transferred from PPE to E&E. As at December 31, 2010, the Company transferred \$29.8 million of these costs from PPE to E&E.

E&E will be expensed if technical feasibility and commercial viability cannot be established. The Company has expensed costs under IFRS related to pre-license and land expiries that were previously capitalized in PPE under Canadian GAAP. The impact is illustrated in the reconciliation of net income above. E&E assets are not amortized.

PP&E and Impairment of Assets

Development and production (D&P) costs include those expenditures for areas or projects where technical feasibility and commercial viability have been determined. Under IFRS, the Company will continue to capitalize these costs within PP&E.

Under Canadian GAAP, with respect to divestitures, there is no recognition of a gain or loss unless the deduction would result in a change to the depletion rate of 20 percent or greater, in which case a gain or loss is recorded. Under IFRS, PP&E divestitures will generally result in recognition of a gain or loss to income. The Company has illustrated this impact in the reconciliation of net income above.

Under IFRS, the Company is required to recognize and measure an impairment loss if the carrying value exceeds the recoverable amount for a cash-generating unit. Under IFRS, the recoverable amount is the higher of fair value less cost to sell and value in use. The Company will group its PP&E assets into six cash-generating units for the impairment calculation. Under Canadian GAAP impairment tests are calculated at the country level. As a result of the accounting policy change, there was no impairment recorded upon transition and comparative periods.

Depreciation and Depletion

The costs are depleted on a unit-of-production basis at a lower unit of account than the country cost centre level currently utilized under Canadian GAAP. The Company determined the area level to be the appropriate unit of account and have used the unit of production basis of depletion and depreciation utilizing proved plus probable reserves. This has resulted in a lower DD&A charge to income. The impact of this change is illustrated in the reconciliation of net income above.

Decommissioning Liability

Under Canadian GAAP, the decommissioning liability (formerly referred to as asset retirement obligation) was measured as the estimated fair value of the retirement and decommissioning expenditures expected to be incurred. In measuring the fair value, the Company used a credit adjusted risk free rate to value the liability. Under IFRS, the asset retirement is measured as the best estimate of the expenditure to be incurred using a lower risk-free discount rate. Therefore, the Company concluded that it should apply a lower risk-free discount rate to value the decommissioning liability. As a result, the Company decommissioning liability increased at the date of transition by \$2.6 million. As at December 31, 2010, excluding the January 1, 2010 adjustment, Rock’s decommissioning liability increased by \$0.3 million and the related accretion of the discount decreased.

Share based payments

Under Canadian GAAP, the Company accounted for options granted to employees and directors by measuring the fair value of the instruments issued and amortized over the vesting periods. The fair value was measured using a Black Scholes option pricing model using share price, exercise price, expected volatility, weighted average expected life, expected dividends and the risk-free rate. Under IFRS, the Company must apply a forfeiture rate on the grant date and subsequently adjust to reflect the actual number of options that vest. Under Canadian GAAP, forfeitures were recorded at the time of the expiry or cancellation. Therefore, the Company recorded an adjustment for the forfeiture rate prospectively which is illustrated above in the net income reconciliation.

Flow-through shares

Flow-through shares are resource expenditure deductions for income tax purposes related to exploratory activities funded by flow-through share arrangements which are renounced to investors in accordance with income tax legislation. Under Canadian GAAP, the accounting treatment for flow-through shares is to record the full amount of the proceeds in share capital. When expenditures are incurred, the related tax affect is recorded to share capital and the future tax liability. Under IFRS, the amount initially recorded in share capital is limited to the amount of common shares that would have been issued on that date and the difference between the actual proceeds and the amount recorded in share capital is set up as a deferred credit premium on flow-through shares. When the expenditures are incurred, the related deferred credit premium on flow-through shares is reversed and the related tax affect is recorded to the future tax liability. The impact on this change in accounting policy resulted in recording a transitional adjustment to share capital and retained earnings of \$890.

Income tax

Deferred income tax has been adjusted to reflect the tax effect arising from the differences between Canadian GAAP and IFRS. The Company illustrates the income tax effect above in the net income reconciliation.

New Accounting Pronouncements

IFRS 9 Financial Instruments, as issued in November 2009 and revised in October 2010 is required to be adopted by 2013, subject to confirmation by the International Accounting Standards Board. The standard addresses classification and measurement of financial assets and replaces the multiple category and measurement models in IAS 39 and divides all financial assets that are currently in the scope of IAS 39 into two classifications; amortized cost and those measured at fair value. The Company has not yet assessed the impact of the standard or determined whether it will adopt the standard early.

IFRS 10 was issued in May 2011 and will replace portions of IAS 27 “Consolidation and Separate Financial Statements” and interpretation SIC-12 “Consolidation – Special Purpose Entities.” The key features of IFRS 10 include consolidation using a single control model, definition of control, considerations on power and continuous reassessment. IFRS 10 is effective for annual periods beginning on or after January 1, 2013 with early adoption permitted. The Company is currently evaluating the impact of IFRS 10 on its financial statements.

IFRS 11, Joint Arrangements will replace IAS 31, Interest in Joint Ventures. The new standard redefines joint operations and joint ventures. Joint operations are required to be proportionately consolidated and joint ventures to be equity accounted. Under IAS 31, joint ventures could be proportionately accounted. IFRS 11 is effective for annual periods beginning on or after January 1, 2013 with early adoption permitted. The Company is currently assessing the impact of the new standard on its financial statements.

IFRS 12, Disclosure of Interests in Other Entities, outlines the required disclosures for interests in subsidiaries and joint arrangements. The new disclosure provides information for users to evaluate the nature, risks and financial effects associated with an entity’s interests in subsidiaries and joint arrangements. IFRS 12 is effective for annual periods beginning on or after January 1, 2013 with early adoption permitted. The adoption of this standard should not have a significant impact on the Company’s financial statements.

IFRS 13, Fair Value Measurement, establishes a common definition of fair value and a framework for measuring fair value under IFRS. The standard also enhances the disclosures required for fair value measurements. IFRS 13 applies when other IFRSs require or permit fair value measurements. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 with early adoption permitted. The Company is assessing the impact of the new standard on its financial statements.

Critical Accounting Estimates

A summary of the Company’s significant accounting policies is contained in note 2 of the Company’s first IFRS condensed interim consolidated financial statements for the periods ended March 31, 2011 and 2010 and for the year ended December 31, 2010. These accounting policies are subject to estimates and key judgements about future events, many of which are beyond Rock’s control. The following is a discussion of the accounting estimates that are critical to the financial statements.

Crude oil and natural gas assets - reserves estimates – Rock retains GLJ to evaluate its crude oil and natural gas reserves, prepare an annual evaluation report, and report to the Reserves Committee of the Board of Directors. The process of estimating crude oil and natural gas reserves is subjective and involves a significant number of decisions and assumptions in evaluating available geological, geophysical, engineering and economic data. These estimates will change over time as additional data from ongoing development and production activities becomes available and as economic conditions affecting crude oil and

natural gas prices and costs change. Reserves can be classified as proved, probable or possible with decreasing levels of likelihood that the reserves will be ultimately produced.

Reserve estimates are a key input to the Company's depletion calculations and impairment tests. Property, plant and equipment within each area are depleted using the unit-of-production method based on proved reserves using estimated future prices and costs. In addition, the costs subject to depletion include an estimate of future costs to be incurred in developing proved reserves. A revision in reserve estimates or future development costs could result in the recognition of higher depletion charged to net income.

Under the IFRS, the carrying amounts of property, plant and equipment are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, the estimated recoverable amount is calculated. For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or "CGU"). The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proven and probable reserves. E&E assets are allocated to the related CGU's to assess for impairment, both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to producing assets (oil and natural gas interests in property, plant and equipment). An impairment loss is recognized in income if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Reserve, revenue, royalty and operating cost estimates and the timing of future cash flows are all critical components of the impairment test. Revisions of these estimates could result in a write-down of the carrying amount of crude oil and natural gas properties.

Decommissioning liabilities – The Company recognizes the estimated fair value of the decommission liability in the period in which it is incurred, and records a corresponding increase in the carrying value of the related asset. The future asset retirement obligation is an estimate based on the Company's ownership interest in wells and facilities and reflects estimated costs to complete the abandonment and reclamation as well as the estimated timing of the costs to be incurred in future periods. Estimates of the costs associated with abandonment and reclamation activities require judgement concerning the method, timing and extent of future retirement activities. The capitalized amount is depleted on a unit-of-production method over the life of the proved and probable reserves. The liability amount is increased each reporting period due to the passage of time and this accretion amount is charged to earnings in the period, which is included as a financing expense. Actual costs incurred on settlement of the decommissioning liability are charged against the liability. Judgements affecting current and annual expense are subject to future revisions based on changes in technology, abandonment timing, costs, discount rates and the regulatory environment.

Commodity price contracts – The Company has entered into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The Company has not designated its financial commodity price contracts as effective accounting hedges. As a result, all financial derivative contracts are classified at fair value through income (loss) and are recorded on the balance sheet at fair value. The estimate of fair value of commodity price contracts requires judgment and incorporated forward market prices. The estimated fair value of financial assets and liabilities is subject to measurement uncertainty.

Share based payments – Stock options issued to employees and directors under the Company's stock option plan are accounted for using the fair value method of accounting for stock-based compensation. The fair value of the option is recognized as a share based payment and contributed surplus over the vesting period of the option. Share based payment is determined on the date of an option grant using the Black-Scholes option pricing model. The Black-Scholes pricing model requires the estimation of several variables including estimated volatility of Rock's stock price over the life of the option, estimated option forfeitures, estimated life of the option, estimated risk-free rate and estimated dividend rate. A change to these estimates would alter the valuation of the option and would result in a different related share based payment.

Income taxes – Rock follows the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Current tax is the expect tax payable on the taxable income for the year, using tax rates enacted or substantially enacted at the reporting period, and any adjustment to tax payable in respect to previous periods. Tax interpretations and legislation in which the Company operates are subject to change. As such, income taxes are subject to measurement uncertainty and interpretations can impact net income through current tax arising from the changes in the deferred income tax asset and liabilities.

Business Risks

Rock is exposed to a number of business risks, some of which are beyond its control, as are all companies in the oil and gas industry. These risks can be categorized as operational, financial and regulatory.

Operational risks include generating, finding and developing, and acquiring oil and natural gas reserves on an economical basis (including acquiring land rights or gaining access to land rights), reservoir production performance, marketing, production, hiring and retaining employees, and accessing contract services on a cost-effective basis. Rock attempts to mitigate these risks by employing highly qualified staff and operating in areas where employees have expertise. In addition the Company outsources certain activities to be able to lever industry expertise, without having the burden of hiring full-time staff given the current scope of operations. Typically the Company has outsourced the marketing and certain engineering and land functions. Rock is attempting to acquire existing oil and natural gas operations; however, Rock will be competing against many other companies for such operations, many of which will have greater access to resources. As a small company, gaining access to contract services may be difficult given the competitive nature of the industry, but Rock will attempt to mitigate this risk by utilizing existing relationships.

Financial risks include commodity prices, the US/Canadian dollar exchange rate and interest rates, all of which are largely beyond the Company's control. Currently Rock has not used any financial instruments to mitigate these risks. The Company would consider using these financial instruments depending on the operating environment. The Company also will require access to capital. Currently Rock has a debt facility in place and intends to use its debt capacity in the future in conjunction with capital expenditures including acquisitions. It intends to use prudent levels of debt to fund capital programs based on the expected operating environment. It also intends to access equity markets to fund opportunities; however, the ability to access these markets will be determined by many factors, many of which will be beyond the control of the Company.

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and are continuing through 2011, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Company may, in part, be determined by the Company's borrowing base. A sustained material decline in prices from historical average prices could reduce the Company's borrowing base, therefore reducing the bank credit available to the Company which could require that a portion of the Company's bank debt be repaid. In the current economic climate, including the recent deterioration in commodity prices, the Company's ability to access both credit and equity markets may be compromised or prohibited as many credit lenders and equity investors are restricting funds available to companies like Rock and as a result, Rock may have to alter its future spending plans.

Environmental Regulation and Risk

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. The Company has put in place a corporate safety program and a site-specific emergency response program to help manage these risks. The Company hires third-party consultants to help develop and manage these programs and help Rock comply with current environmental legislation. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". Recently, representatives from approximately 170 countries met in Copenhagen, Denmark to attempt to negotiate a successor to the Kyoto Protocol. Pursuant to the resulting Copenhagen Accord, a non-binding political consensus rather than a binding international treaty such as the Kyoto Protocol, the Government of Canada revised its emissions reduction targets

slightly. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and may require the Corporation to comply with Alberta's greenhouse gas emissions legislation contained in the *Climate Change and Emissions Management Act* and the *Specified Gas Emitters Regulation*. The Corporation may also be required to comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which is now expected to be modified to ensure consistency with the regulatory scheme for greenhouse gas emissions adopted by the United States and may include facility-specific targets for upstream exploration and production facilities. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gas regulations, whether to meet the limits required by the Kyoto Protocol, the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation.

There were no changes to environmental regulations and risks during the first nine months of 2011, from those outlined in the MD&A of the Company as at December 31, 2010 which has been filed on SEDAR at www.sedar.com.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact of those requirements on the Company and its operations and financial condition.

Rock Energy Inc.

Condensed Interim Consolidated Statement of Financial Position
(unaudited)

(all amounts in \$000)	Notes	September 30, 2011	December 31, 2010
Assets			(note 16)
Accounts receivable		\$ 6,304	\$ 8,025
Prepaid expenses and deposits		762	781
Commodity price contracts	6	2,181	-
		9,247	8,806
Exploration and evaluation	4	42,186	29,788
Property, plant and equipment (net)	5	143,579	127,098
		185,765	156,886
		\$ 195,012	\$ 165,692
Liabilities			
Accounts payable and accrued liabilities		\$ 10,364	\$ 16,612
Bank debt	8	30,822	24,558
Commodity price contracts - current portion	6	-	1,252
		41,186	42,422
Commodity price contracts	6	-	619
Deferred price premium on flow-through shares	13	1,509	769
Deferred income tax liability		4,726	3,892
Decommissioning liability	9	13,842	11,812
		20,077	17,092
Shareholders' Equity			
Share capital	10	133,644	105,285
Contributed surplus	10	6,251	5,112
Deficit		(6,146)	(4,219)
		133,749	106,178
Commitments	15		
		\$ 195,012	\$ 165,692

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

Rock Energy Inc.

Condensed Interim Consolidated Statements of Income (Loss) and Comprehensive Income (Loss)
(unaudited)

		Three Months Ended Sept 30, 2011	Three Months Ended Sept 30, 2010	Nine Months Ended Sept 30, 2011	Nine Months Ended Sept 30, 2010	
(\$000 except per share amounts)						
<i>Revenue</i>			(note 16)		(note 16)	
Oil and natural gas revenue	\$	13,928	\$	15,497	\$	47,622
Royalties		(2,699)		(2,317)		(7,368)
Realized loss on commodity price contracts	6	(19)		(825)		-
Unrealized gain on commodity price contracts	6	4,169		-		-
		15,379		13,180		40,254
<i>Expenses</i>						
Production and operating		5,777		5,496		20,175
General and administrative	11	1,399		1,147		4,491
Exploration and evaluation	4	358		22		690
Finance expenses	12	354		347		1,105
Depletion and depreciation	5	6,623		4,838		18,662
Impairment loss	5	-		-		5,370
Gain on sale of properties	5	-		-		(7,536)
		14,511		11,850		42,957
Income (loss) before income taxes		868		1,330		(1,694)
Deferred income taxes		409		457		233
Net income (loss) and comprehensive income (loss) for the period	\$	459	\$	873	\$	(1,927)
		\$ 0.01		\$ 0.03		\$ (0.05)
Basic and diluted net income (loss) per share	10					0.10

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

Rock Energy Inc.

Condensed Interim Consolidated Statements of Changes in Shareholders' Equity
(unaudited)

(\$000)	Notes	Share capital	Contributed Surplus	Deficit	Shareholders' Equity	Total
Balance at January 1, 2010		\$ 97,115	\$ 4,530	\$ (5,068)	\$	96,577
Share based payments	11	407	184	-		591
Net income for the period		-	-	3,002		3,002
Balance at September 30, 2010		\$ 97,522	\$ 4,714	\$ (2,066)	\$	100,170

(\$000)	Notes	Share capital	Contributed Surplus	Deficit	Shareholders' Equity	Total
Balance at December 31, 2010		\$ 105,285	\$ 5,112	\$ (4,219)	\$	106,178
Share based payments	11	-	1,251	-		1,251
Issued on exercise of options	10	317	(112)	-		205
Issued for cash on equity financing	10	21,190	-	-		21,190
Issued for flow-through shares	10	10,004	-	-		10,004
Share issue costs (net of deferred income taxes of \$461)	10	(1,348)	-	-		(1,348)
Deferred price premium on flow-through shares	13	(1,804)	-	-		(1,804)
Net loss for the period		-	-	(1,927)	\$	(1,927)
Balance at September 30, 2011		\$ 133,644	\$ 6,251	\$ (6,146)	\$	133,749

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

Rock Energy Inc.

Condensed Interim Consolidated Statements of Cash Flows
(unaudited)

(all amounts in \$000)	Notes	Three Months Ended Sept 30, 2011	Three Months Ended Sept 30, 2010	Three Months Ended Sept 30, 2011	Three Months Ended Sept 30, 2010	Nine Months Ended Sept 30, 2011	Nine Months Ended Sept 30, 2010
			(note 16)				(note 16)
Cash flows from operating activities:							
Net income (loss) for the period		\$ 459	\$ 873	\$ (1,927)		\$ 3,002	
Adjustments for non - cash items:							
Exploration and evaluation expense		358	22	690		770	
Depletion and depreciation		6,623	4,838	18,662		14,047	
Impairment loss		-	-	5,370		-	
Unrealized gain on commodity price contracts		(4,169)	-	(4,052)		-	
Gain on sale of properties		-	-	(7,536)		-	
Share based payments	11	260	275	871		580	
Finance expenses (accretion)	12	53	41	150		123	
Deferred income taxes		409	457	233		1,230	
Decommissioning expenditures		(93)	(89)	(298)		(208)	
Changes in non-cash working capital	14	615	4,986	(93)		3,629	
Cash from operating activities		4,515	11,403	12,070		23,173	
Cash flows from investing activities:							
Capital expenditures		(14,653)	(9,160)	(42,017)		(29,838)	
Acquisition		(267)	-	(13,246)		-	
Disposition		(32)	-	11,755		-	
Changes in non-cash working capital	14	1,487	(2,422)	(4,415)		(5,469)	
Cash used in investing activities		(13,465)	(11,582)	(47,923)		(35,307)	
Cash flows from financing activities:							
Issuance of common shares		(18)	-	29,385		-	
Exercise of share options		137	38	204		(309)	
Proceeds from bank debt		8,831	141	6,264		12,443	
Cash from financing activities		8,950	179	35,853		12,134	
Change in cash		-	-	-		-	
Cash, beginning of period		-	-	-		-	
Cash, end of period		\$ -	\$ -	\$ -		\$ -	
Interest paid in cash		\$ 464	\$ 257	\$ 1,027		\$ 768	

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

Rock Energy Inc.

Notes to Condensed Interim Consolidated Financial Statements
(Unaudited)

For the period ended September 30, 2011, with comparative figures for 2010

(all amounts in text and tables are in \$000 except per share amounts, numbers of shares and options, and other exceptions as indicated)

1. REPORTING ENTITY

Rock Energy Inc. (“the “Company” or “Rock”) is a publicly traded company incorporated under the laws of Alberta. Rock and its wholly owned subsidiaries are engaged in the exploration, development and production of crude oil and natural gas in Western Canada.

2. BASIS OF PRESENTATION

Statement of compliance

The condensed interim consolidated financial statements present Rock’s financial results of operations and financial position under International Financial Reporting Standards (“IFRS”) for the period ended September 30, 2011, including 2010 comparable periods. IFRS 1 *First-time Adoption of IFRS* and International Accounting Standard (“IAS”) 34 *Interim Financial Reporting* have been applied. These condensed interim Consolidated Financial Statements may not include all the necessary annual disclosures in accordance with IFRS.

These unaudited condensed interim financial statements have been prepared following the same accounting policies and methods of computation as the Company’s first IFRS condensed interim consolidated financial statements for the periods ended March 31, 2011 and 2010. These unaudited condensed interim consolidated financial statement and notes should be read in conjunction with Rock’s first IFRS condensed interim consolidated financial statements for the period ended March 31, 2011 and 2010.

The impact of adoption from Canadian GAAP to IFRS for the period ended September 30, 2010 is presented in note 16.

The condensed interim consolidated financial statements for the periods ended September 30, 2011 and 2010 were approved and authorized for issue by the Board of Directors on November 8th, 2011.

Basis of measurement

The condensed interim consolidated financial statements have been prepared on the historical cost basis except for certain financial assets and liabilities (note 6) which are measured at fair value.

Functional and presentation currency

The condensed interim consolidated financial statements are presented in Canadian dollars, which is the Company’s functional currency.

Use of estimates and judgments

The preparation of financial statements requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Information about significant areas of estimation uncertainty and critical judgements in applying accounting policies that have the most significant effect on the amounts recognized in the condensed interim consolidated financial statements is included in the following notes:

- Note 4 – valuation of exploration and evaluation
- Note 5 – valuation of property, plant and equipment, depletion and depreciation and impairment of assets
- Note 6 – valuation of financial instruments
- Note 9 – decommissioning liability and accretion
- Note 11 – measurement of share-based payments

Crude oil and natural gas reserve estimates impact a number of the areas referred to above in particular, the valuation of property, plant and equipment and the calculation of depletion and depreciation.

3. SIGNIFICANT ACCOUNTING POLICIES

These unaudited condensed interim financial statements have been prepared following the same accounting policies and methods of computation as the Company's first IFRS condensed interim consolidated financial statements for the periods ended March 31, 2011 and 2010. Rock's significant accounting policies are presented in note 3 of the first IFRS condensed interim consolidated financial statements for the periods ended March 31, 2011 and 2010.

The impact of the transition from Canadian Generally Accepted Accounting Principles ("GAAP") to IFRS for the period ended September 30, 2010 is explained in note 16.

4. EXPLORATION AND EVALUATION

	Intangible Exploration Assets
<i>Cost:</i>	
Balance at January 1, 2010	\$ 20,762
Additions	11,772
Transfers to property, plant and equipment	(782)
Transfers to exploration and evaluation expense	(1,964)
Balance at December 31, 2010	29,788
Additions	18,497
Transfers to property, plant and equipment	(5,042)
Transfers to exploration and evaluation expense	(690)
Acquisitions	148
Dispositions	(515)
Balance at September 30, 2011	\$ 42,186

E&E assets consist of the Company's unproved properties and capitalized exploration drilling and completion costs which are pending the determination of commercial feasibility. The Company assesses the recoverability of E&E assets, before and at the moment of reclassification to property, plant and equipment, within the Company's cash-generating unit ("CGU"). The CGU's include both E&E assets and assets related to oil and natural gas interests for that area. During the three and nine months ended September 30, 2011, the Company expensed \$358 (2010 - \$22) and \$690 (2010 - \$770) related to pre-license costs and land expiries.

During the nine months ended September 30, 2011, \$99 (2010 - nil) of directly attributable administrative costs were capitalized as part of exploration and evaluation assets.

5. PROPERTY, PLANT AND EQUIPMENT

	Petroleum and natural gas properties	Office equipment	Total
<i>Deemed cost:</i>			
Balance at December 31, 2010	\$ 145,577	\$ 1,614	\$ 147,191
Additions	26,293	284	26,577
Transfer from intangible exploration assets	5,042	-	5,042
Acquisitions	13,098	-	13,098
Dispositions (net of gain of \$7,036)	(6,490)	-	(6,490)
Balance at September 30, 2011	\$ 183,520	\$ 1,898	\$ 185,418
<i>Accumulated depletion and depreciation:</i>			
Balance at December 31, 2010	\$ 19,279	\$ 814	\$ 20,093
Depletion and depreciation expense for the period	18,539	123	18,662
Impairment loss	5,370	-	5,370
Dispositions	(2,286)	-	(2,286)
Balance at September 30, 2011	\$ 40,902	\$ 937	\$ 41,839
<i>Carrying amounts:</i>			
At December 31, 2010	\$ 126,298	\$ 800	\$ 127,098
At September 30, 2011	\$ 142,618	\$ 961	\$ 143,579

(a) Depletion and depreciation and impairment

The depletion, depreciation and impairment of property, plant and equipment, and any eventual reversal thereof, are recognized in depletion and depreciation in earnings. At September 30, 2011, the Company included \$37,414 of future development costs (September 30, 2010 – \$13,624) into the net carrying value of development or production assets, subject to depletion as those costs are necessary to bring the proved and probable reserves into production.

During the second quarter of 2011, Rock recognized a \$5,370 impairment loss relating to a CGU consisting of natural gas properties. The impairment was based on the difference between the period-end net book value of the assets and the recoverable amount determined using fair value less costs to sell based on discounted cash flows of proved and probable reserves using forecast prices and costs.

(b) Property acquisition and disposition

On February 23, 2011 Rock completed the acquisition of certain heavy oil properties for \$13,246. In addition, the Company disposed of certain non-core producing natural gas assets for cash consideration of \$11,755. The Company recorded a \$7,036 gain to earnings related to the sale of these properties.

On June 3, 2011, the Company disposed of certain petroleum and natural gas rights for proceeds of \$500 and recorded a \$500 gain to earnings related to the sale.

(c) Capitalized general and administrative expense

During the three and nine months ended September 30, 2011, \$377 (2010 - \$354) and \$1,307 (2010 - \$1,203) of directly attributable administrative costs were capitalized as part of property, plant and equipment.

6. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Fair Value of Financial Instruments

The Company's exposure under its financial instruments is limited to financial assets and liabilities, all of which are included in these financial statements. The fair values of the financial assets and liabilities included in the balance sheet approximate their carrying amounts.

The Company is required to present information about financial instruments measured at fair value in accordance with a three-level hierarchy. The Company's commodity oil price contracts, which are recorded at fair value on a recurring basis, have been classified in one of the following three categories based on this fair-value hierarchy:

- Level 1 – quoted prices are available in active markets for identical assets or liabilities;
- Level 2 – pricing inputs other than quoted prices in active markets included in level 1, which are observable either directly and/or indirectly; and
- Level 3 – inputs for the asset or liability that are not based on observable market data.

Rock's commodity price contracts have been classified as Level 2 as the estimation of fair value incorporates forward prices. Assessment of the significance of a particular input to the fair value measurement requires judgement and may affect the financial instrument's placement in the hierarchy.

Commodity Price Risk

Due to the volatile nature of commodity prices the Company could be exposed to adverse consequences if commodity prices decline. However, if commodity prices are hedged, future gains from rising commodity prices would be forfeited to varying degrees depending on the nature and degree of hedging. Commodity prices for petroleum and natural gas are impacted not only by the relationship between the Canadian and United States dollars, as outlined below, but also global economic events that dictate the levels of supply and demand. A \$1.00 per barrel change for its oil and natural gas liquids production is estimated to result in a \$109 change in after tax net income (loss) for the third quarter of 2011. A \$0.25 per mcf change in the Company's realized sales price for its natural gas production is estimated to result in a \$70 change in after tax net income (loss) for the third quarter of 2011.

The Company may utilize commodity price contracts to manage market risks. All such transactions are conducted in accordance with the risk management policy that has been approved by the Board of Directors. The Company has attempted to mitigate commodity price risk through the use of commodity price contracts. As at September 30, 2011, the Company has fixed the price applicable to future production through the following contracts:

Type of Contract	Commodity	Average Quantity	Contract Price (US \$/bbls)	Pricing Point	Term
Financial	Crude oil	1,100 bbls/d	\$80.00 floor / \$96.80 ceiling	WTI - NYMEX	January 2011 - December 2011
Financial	Crude oil	400 bbls/d	\$80.00 floor / \$96.80 ceiling	WTI - NYMEX	January 2012 - December 2012
Financial	Crude oil	400 bbls/d	\$92.60 floor / \$109.60 ceiling	WTI - NYMEX	January 2012 - March 2012
Financial	Crude oil	300 bbls/d	\$90.00 floor / \$106.85 ceiling	WTI - NYMEX	January 2013 - March 2013

The fair value of these contracts as at September 30, 2011 is an asset of \$2,181 (December 31, 2010 – liability of \$1,871). For the three and nine months ended September 30, 2011, the Company recognized a gain on these contracts of \$4,150 and \$3,227 composed of an unrealized gain of \$4,169 and \$4,052 and a realized loss of \$19 and \$825, respectively.

Subsequent to September 30, 2011, the Company settled the following crude oil commodity contracts and realized a gain of \$1,691;

Type of Contract	Commodity	Average Quantity	Contract Price (US \$/bbls)	Pricing Point	Term
Financial	Crude oil	400 bbls/d	\$80.00 floor / \$96.80 ceiling	WTI - NYMEX	January 2012 - December 2012
Financial	Crude oil	400 bbls/d	\$92.60 floor / \$109.60 ceiling	WTI - NYMEX	January 2012 - March 2012
Financial	Crude oil	300 bbls/d	\$90.00 floor / \$106.85 ceiling	WTI - NYMEX	January 2013 - March 2013

Foreign Currency Exchange Risk

The Company is exposed to foreign currency fluctuations as crude oil and natural gas prices received are referenced in U.S. dollar-denominated prices. As at September 30, 2011 the Company does not have any foreign currency exchange contracts in place.

Credit Risk

Substantially all of the Company's accounts receivable are with customers, joint interest partners, and oil and natural gas marketers, and are subject to normal industry credit risks. Receivables from customers, joint interest partners and oil and natural gas marketers are generally collected within one to three months. The Company attempts to mitigate this risk by entering into transactions with longstanding and reputable organizations and by obtaining partner approval of significant capital expenditures and payment of cash advances whenever possible. Further risk exists with joint interest partners as disagreements occasionally arise and may increase the potential for non-collection. Currently, there is no indication that amounts are non-collectable; thus, an allowance for doubtful accounts has not been set up. Receivables related to oil and natural gas marketers are normally collected on the 25th day of the month following production. To mitigate the risk on these receivables the Company will predominately establish relationships with large marketers that have strong credit ratings and solid reputations. Historically, the Company has not experienced any issues in collecting from its oil and natural gas marketers. As at September 30, 2011 the Company's receivables consist of \$822 (December 31, 2010 – \$225) from joint interest partners, \$4,973 (December 31, 2010 – \$6,007) from oil and natural gas marketers, \$ nil (December 31, 2010 – \$1,259) of drilling incentive credits and \$509 (December 31, 2010 – \$534) of other trade receivables.

Interest Rate Risk

The Company is exposed to interest rate risk to the extent that bank debt is subject to a floating short-term rate of interest. The Company does not have any interest rate contracts in place as of September 30, 2011. A one percent change to the floating short-term interest rates is estimated to result in a \$56 (2010 - \$62) change in after tax net income (loss) for the third quarter of 2011.

7. CAPITAL MANAGEMENT

In order to continue the Company's future exploration and development program, the Company must maintain a strong balanced capital structure. A strong capital base helps the Company to access the equity and debt markets when deemed advisable and to maintain existing shareholders as well as attract new investors. In order to maintain a strong capital base, the Company continually monitors the risk-reward profile of its exploration and development projects and the economic indicators in the market including commodity prices, interest rates and foreign exchange rates. The Company attempts to minimize the impact of commodity price volatility by entering into commodity price contracts. It then determines the need for any increases or decreases to its capital budget.

The Company considers shareholders' equity, bank debt and working capital to be components of its capital base. The Company can access or increase capital through the issuance of shares, through bank borrowings, which are based on crude oil and natural gas reserves.

	September 30, 2011	December 31, 2010
Shareholders' equity	\$ 133,749	\$ 106,178
Bank debt	\$ 30,822	\$ 24,558
Working capital deficiency (excluding bank debt)	\$ 1,117	\$ 7,806

The Company monitors its capital based primarily on its ratio of debt to annualized funds flow. Debt includes bank debt plus or minus working capital. Annualized funds flow is calculated as cash flow from operations before changes in non-cash working capital and asset retirement expenditures from the Company's most recent quarter multiplied by four. The Company intends to manage its debt at a ratio of approximately 1.5:1 depending on the timing and nature of the Company's activities. As September 30, 2011, the Company

debt to annualized funds flow has temporarily exceeded this desired level due to significant current capital expenditures. To facilitate the management and control of this ratio, the Company prepares an annual operating and capital expenditure budget. The budget is updated when critical factors change. These factors include economic factors such as the state of equity markets, changes to commodity prices, interest rates and foreign exchange rates and non-economic factors such as the Company's drilling results and its production profile. The Company's Board of Directors approves the budget and changes thereto. At September 30, 2011, the Company's debt-to-annualized-funds-flow ratio was 2.0:1.

The Company's share capital is not subject to external restrictions but the Company has financial covenants in regards to its operating bank facility. The facility requires that the Company maintain a working capital ratio, as defined, of not less than 1:1. The calculation allows for the unused portion of the credit facility to be added to current assets and the deduction of the current portion of bank debt from the current liabilities (excluding commodity price contracts). The Company is in compliance with this covenant as at September 30, 2011.

8. BANK DEBT

The Company has a demand operating credit facility with a Canadian chartered bank subject to the bank's evaluation of the Company's crude oil and natural gas properties. The limit under the facility is \$62,000. The facility is secured by a first ranking floating charge on all real property of the Company, its subsidiary and partnership, and a general security agreement. The facility bears interest at the bank's prime rate or at the prevailing bankers' acceptance rate plus an applicable bank fee, which varies depending on the Company's debt-to-funds-from-operations ratio (as defined by the lender). The facility also bears a standby charge for un-drawn amounts. The amount of the facility is subject to a borrowing base test performed on a periodic basis by the lender, based primarily on reserves using commodity prices estimated by the lender as well as other factors. A decrease in the borrowing base could result in a reduction to the credit facility. The next review of the facility is scheduled to be completed by January, 2012.

9. DECOMMISSIONING LIABILITY

The decommissioning liability results from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its decommissioning liability at September 30, 2011 to be approximately \$16,894 (December 31, 2010 – \$12,962) including expected annual inflation of 1.5 percent (December 31, 2010 – 1.5 percent). A risk-free rate of 3.14 percent (December 31, 2010 – 3.14 percent) was used to calculate the fair value of the liability. These obligations are expected to be incurred from the current year through 2028 and are expected to be funded through general corporate funds at the time of settlement.

The following table outlines a reconciliation of the decommissioning liability:

	Nine Months Ended September 30, 2011	Year Ended December 31, 2010
Opening balance	\$ 11,812	\$ 10,089
Liabilities incurred	2,387	1,889
Accretion	150	151
Revision/Dispositions	(209)	(76)
Abandonment expenditures	(298)	(241)
Closing balance	\$ 13,842	\$ 11,812

10. SHARE CAPITAL AND CONTRIBUTED SURPLUS

(a) Authorized

Unlimited number of voting common shares, without stated par value. 300,000 preferred shares, without stated par value, of which none have been issued.

(b) Common shares issued

	Number	Amount
Issued and outstanding on January 1, 2010	30,557,243	\$ 97,115
Issued on exercise of stock options	279,836	407
Issued and outstanding on September 30, 2010	30,837,079	\$ 97,522
	Number	Amount
Issued and outstanding on December 31, 2010	32,753,746	\$ 105,285
Issued on exercise of stock options	154,469	317
Issued for cash on equity financing (i)	4,238,100	21,190
Issued for flow-through shares (ii)	1,640,000	10,004
Share issue costs (net of future income taxes of \$461)	-	(1,348)
Deferred price premium on flow-through shares	-	(1,804)
Issued and outstanding on September 30, 2011	38,786,315	\$ 133,644

(i) The Company completed an equity financing on May 19, 2011 for 4,238,100 common shares at an issue price of \$5.00 per common share for gross proceeds of \$21,190.

(ii) The Company completed an equity financing on a flow-through basis on May 19, 2011 of 1,640,000 common shares at \$6.10 per share for gross proceeds of \$10,004. The Company estimated the flow-through premium to be \$1.10/share.

(c) Stock options

The Company has a stock option plan under which it may grant options to directors, officers and employees for the purchase of up to 10 percent of the issued and outstanding common shares of the Company. Options are granted at the discretion of the Board of Directors. The exercise price, vesting period and expiration period are also fixed at the time of grant at the discretion of the Board of Directors. The initial grant of options vests yearly in one-third tranches beginning on the first anniversary of the grant date and expires one year after vesting. Options granted to replace an expiring tranche, if applicable, vest in two years and expire in three years. The following table summarizes the stock options outstanding at September 30, 2011 and December 31, 2010 and changes during the years ended on those dates:

	Number of Options	Weighted Average Exercise Price
December 31, 2009	1,592,248	\$ 1.06
Granted	1,160,900	4.32
Exercised	(478,139)	0.96
Forfeited	(232,714)	1.22
December 31, 2010	2,042,295	\$ 2.92
Granted	1,054,400	5.37
Exercised	(154,469)	1.32
Forfeited	(389,532)	4.21
Expired	(1,600)	0.88
September 30, 2011	2,551,094	\$ 3.83

Options outstanding and exercisable under the stock option plan are summarized below as at September 30, 2011:

Outstanding Options				Exercisable Options		
Exercise Price	Number of Options	Weighted Average Exercise Price	Weighted Average Years to Expiry	Number of Options		Weighted Average Exercise Price
\$0.84 - \$0.99	536,262	\$ 0.88	1.04	259,435	\$	0.88
\$1.61 - \$2.09	173,332	\$ 1.96	1.32	70,000	\$	2.05
\$4.06 - \$4.54	872,100	\$ 4.19	1.51	296,036	\$	4.18
\$4.62 - \$5.11	123,600	\$ 4.86	1.69	41,200	\$	4.86
\$5.52 - \$5.69	845,800	\$ 5.56	2.46	-	\$	-
	2,551,094	\$ 3.83	1.72	666,671	\$	2.72

(d) Contributed surplus:

Changes in the contributed surplus account for the period ended September 30, 2011 and year ended December 31, 2010 outlined as follows:

	Nine months ended September 30, 2011		Year ended December 31, 2010	
Opening balance	\$	5,112	\$	4,530
Share based compensation		1,251		1,340
Net benefit on options exercised (i)		(112)		(758)
Closing balance	\$	6,251	\$	5,112

(i) The benefit of options exercised or repurchased is recorded as a reduction of contributed surplus and an increase to share capital.

(e) Per share amounts

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average number of common shares outstanding for the three months ended September 30, 2011 was 38,785,216 (September 30, 2010 – 30,852,318) and 35,717,746 (September 30, 2010 – 30,656,682) for the nine months ended September 30, 2011. For the three months ended September 30, 2011, 470,119 (September 30, 2010 – 862,517) were added to the weighted average shares outstanding for the dilutive effect of employee stock options. For the nine month period ended September 30, 2011, all outstanding stock options were anti-dilutive.

11. SHARE BASED PAYMENTS

Options granted to employees and directors are accounted for using the fair value method. The fair value of 1,054,400 common share options granted during the nine months ended September 30, 2011 was estimated to be \$1,908. The fair value of common share options as at the grant date is determined using the Black-Scholes option pricing model with the following assumptions for options issued during the period:

Risk free interest rate (%)	2.0%
Expected life (years)	3.0
Expected volatility (%)	71%
Expected dividend yield (%)	0.0%
Forfeiture rate (%)	9.4%
Weighted average fair value per share (\$)	\$2.54

During the three and nine months ended September 30, 2011, the Company recorded share based payments of \$396 (September 30, 2010 - \$426) and \$1,251 (September 30, 2010 - \$900) of which \$260 (September 30, 2010 - \$275) and \$871 (September 30, 2010 - \$580) was recognized as an expense, \$132 (September 30, 2010 – \$151) and \$368 (September 30, 2010 - \$320) was capitalized to property, plant and equipment and \$4 (September 30, 2010 – nil) and \$12 (September 30, 2010 – nil) was capitalized to exploration and evaluation assets.

12. FINANCE EXPENSES

	September 30, 2011		September 30, 2010	
Interest on bank debt	\$	955	\$	755
Accretion of decommissioning liability		150		123
Net finance expenses recognized in earnings	\$	1,105	\$	878

13. DEFERRED PRICE PREMIUM ON FLOW-THROUGH SHARES

	Amount
Deferred price premium on flow-through shares (i)	\$ 1,855
Flow-through premium reversal (ii)	(1,086)
Balance at December 31, 2010	769
Flow-through premium reversal (iii)	(769)
Deferred price premium on flow-through shares (iv)	1,804
Flow-through premium reversal (v)	(295)
Balance at September 30, 2011	\$ 1,509

(i) The Company completed an equity financing on a flow-through basis on November 16, 2010 of 1,855,000 common shares at \$5.40 per share for gross proceeds of \$10,017. The Company estimated the flow-through premium to be \$1.00/share.

(ii) At December 31, 2010, the Company had incurred \$5,900 on qualifying exploration and development activity resulting in the reversal of the deferred price premium related to those expenditures and recorded the related tax effect of \$1,086.

(iii) At March 31, 2011, the Company incurred the remaining \$4,117 from the 2010 financing on qualifying exploration and development activity and reversed the remaining portion of the deferred price premium and the related tax effect of \$769.

(iv) The Company completed an equity financing on a flow-through basis on May 19, 2011 of 1,640,000 common shares at \$6.10 per share for gross proceeds of \$10,004. The Company estimated the flow-through premium to be \$1.10/share.

(v) At September 30, 2011, the Company had incurred \$1,635 on qualifying exploration and development activity and reversed \$295 of the deferred price premium and the related tax effect.

14. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital for the nine months ended September 30, 2011 and September 30, 2010 is comprised of:

	September 30, 2011	September 30, 2010
Accounts receivable	\$ 1,721	\$ 2,121
Prepaid expenses and deposits	19	410
Accounts payable and accrued liabilities	(6,248)	(4,371)
	\$ (4,508)	\$ (1,840)
Related to operating activities	\$ (93)	\$ 3,629
Related to investing activities	\$ (4,415)	\$ (5,469)

15. COMMITMENTS

The Company has the following obligations with fixed terms:

	2011	2012
Office lease premises	\$ 218	\$ 581
Processing arrangements	\$ 52	\$ 159

During the 2011 fiscal year, the Company issued flow-through shares totaling \$10,004 resulting in an obligation to incur qualifying exploration expenditures. As at September 30, 2011, the Company incurred \$1,635 of qualifying exploration expenditures and consequently \$8,369 remains to be incurred prior to December 31, 2012.

16. ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS

As stated in note 2, these unaudited condensed interim consolidated financial statements at September 30, 2011 and 2010 have been prepared following the same accounting policies and methods of computation as the Company's first IFRS condensed interim consolidated financial statements for the periods ended March 31, 2011 and 2010. These unaudited condensed interim consolidated financial statement and notes should be read in conjunction with Rock's first IFRS condensed interim consolidated financial statements for the period ended March 31, 2011 and 2010. A summary of significant accounting policy changes, applicable exemptions and reconciliations at January 1, 2010 (the Company's date of transition) are provided in the Company's first IFRS condensed interim consolidated financial statements.

The following reconciliations present the adjustments made from Canadian GAAP to IFRS to illustrate how the adoption of IFRS has affected the Company's financial position, financial performance and cash flows as at September 30, 2010. A summary of the significant accounting policy changes are discussed following the reconciliations.

Reconciliation of Equity at September 30, 2010

(all amounts in \$000)	Notes	Canadian GAAP	Effect of transition to IFRS	IFRS
Assets				
Accounts receivable		\$ 8,634	-	\$ 8,634
Prepaid expenses and deposits		914	-	914
		9,548	-	9,548
Exploration and evaluation	16 (a)	-	22,286	22,286
Property, plant and equipment (net)	16 (a), (b), (c), (d)	144,502	(16,100)	128,402
		144,502	6,186	150,688
		\$ 154,050	6,186	\$ 160,236
Liabilities				
Account payable and accrued liabilities		\$ 10,043	-	\$ 10,043
Bank debt		35,440	-	35,440
		45,483	-	45,483
Deferred income tax liability	16 (e), (f)	2,024	860	2,884
Decommissioning liability	16 (b)	8,824	2,875	11,699
		10,848	3,735	14,583
Shareholders' Equity				
Share capital	16 (e)	96,575	947	97,522
Contributed surplus	16 (c)	4,781	(67)	4,714
Deficit		(3,637)	1,571	(2,066)
		97,719	2,451	100,170
		\$ 154,050	6,186	\$ 160,236

Reconciliation of condensed interim consolidated statement of income (loss) for the three months ended September 30, 2010

(all amounts in \$000)	Notes	Canadian GAAP	Effect of transition to IFRS	IFRS
<i>Revenue</i>				
Oil and natural gas revenue		\$ 15,497	- \$	15,497
Royalties		(2,317)	-	(2,317)
		13,180	-	13,180
<i>Expenses</i>				
Production and operating		5,496	-	5,496
General and administrative	16 (c)	1,160	(13)	1,147
Exploration and evaluation	16 (a)	-	22	22
Finance expense	16 (b)	440	(93)	347
Depletion and depreciation	16 (d)	6,979	(2,141)	4,838
		14,075	(2,225)	11,850
Income before income taxes		(895)	2,225	1,330
Deferred income taxes (reduction)	16 (e), (f)	(116)	573	457
Net income (loss) and comprehensive income (loss) for the period		\$ (779)	1,652 \$	873

Reconciliation of condensed interim consolidated statement of income (loss) for the nine months ended September 30, 2010

(all amounts in \$000)	Notes	Canadian GAAP	Effect of transition to IFRS	IFRS
<i>Revenue</i>				
Oil and natural gas revenue		\$ 47,622	- \$	47,622
Royalties		(7,368)	-	(7,368)
		40,254	-	40,254
<i>Expenses</i>				
Production and operating		16,416	-	16,416
General and administrative	16 (c)	3,939	(28)	3,911
Exploration and evaluation	16 (a)	-	770	770
Finance expense	16 (b)	1,132	(254)	878
Depletion and depreciation	16 (d)	20,447	(6,400)	14,047
		41,934	(5,912)	36,022
Income before income taxes		(1,680)	5,912	4,232
Deferred income taxes (reduction)	16 (e), (f)	(353)	1,583	1,230
Net income (loss) and comprehensive income (loss) for the period		\$ (1,327)	4,329 \$	3,002

(a) Exploration and evaluation expenditures

Under Canadian GAAP, PP&E included certain E&E expenditures incurred within established geographic areas. Under IFRS, E&E costs related to each license/prospect are initially capitalized within exploration and evaluation assets. The costs are accumulated in cost centres by well, field or exploration area pending determination of technical feasibility and commercial viability. The Company does not deplete E&E assets.

The asset will be transferred to PP&E if technical and economic feasibility have been established by proved reserve assignment. The asset will be expensed if it has been determined there is no future value. As a result, the Company transferred \$22,286 to E&E assets from PP&E as at September 30, 2010. For the three and nine months ended September 30, 2010 the Company expensed \$22 and \$770 related to pre-license costs and undeveloped land expiries.

(b) Decommissioning liability

Under Canadian GAAP decommissioning obligations were discounted at a credit adjusted risk free rate of 8 percent. Under IFRS the estimated cash flow to abandon and remediate the wells and facilities has been risk adjusted therefore the provision is discounted at a risk free rate of 3 percent. As a result of the lower discount rate, the Company recorded additional asset retirement additions to PP&E and lower related accretion costs. In addition, under Canadian GAAP accretion of the discount was included in depletion and depreciation, however is shown as financing expense under IFRS.

For the three and nine months ended September 30, 2010 accretion of the decommissioning liability decreased \$93 and \$254 respectively.

As a result of the change in the discount rate at September 30, 2010, the decommissioning liability and property, plant and equipment increased \$2,875 and \$573 respectively.

(c) Share based payments

Under Canadian GAAP, the Company recognized an expense related to their share based payments on a straight-line basis through the date of full vesting without incorporating a forfeiture multiple. Under IFRS, the Company is required to recognize the expense over the individual vesting periods for the graded vesting awards including an estimated forfeiture rate. The impact on transition was a decrease to contributed surplus of \$23 with an offsetting increase to opening deficit. For the period ended September 30, 2010 contributed surplus decreased \$44 and property, plant and equipment decreased \$18 with an offsetting increase to deficit of \$26.

The impact of estimating a forfeiture rate for the three and nine months ended September 30, 2010 resulted in a decrease in general and administration expense of \$13 and \$28 respectively.

(d) Depletion policy

Upon transition to IFRS, the Company adopted a policy of depleting oil and natural gas interests on a unit of production basis over proved plus probable reserves. Under this method, future development costs are added to the net book value of assets to be depleted. IFRS requires depletion and depreciation to be calculated based on individual components, which the Company has determined to be by area.

Under Canadian GAAP, the Company depleted total development and producing assets on a unit of production basis over total proved reserves.

As a result of the change in the policy of depleting oil and natural gas interests on a proved plus probable basis the impact for the three and nine months ended September 30, 2010 was a decrease in depletion expense of \$2,141 and \$6,400 respectively with a corresponding increase to property, plant and equipment.

(e) Flow-through Shares

Under Canadian GAAP, the accounting treatment for flow-through shares is to record the full amount of the proceeds in share capital. When expenditures are renounced, the related tax affect is recorded to share capital and the future tax liability. Under IFRS, the amount initially recorded in share capital is limited to the amount of common shares that would have been issued on that date and the difference between the actual proceeds and the amount recorded in share capital is set up as a deferred price premium on flow-through shares. When the expenditures are incurred, the related deferred price premium on flow-through shares is reversed and the related tax affect is recorded to the future tax liability. The impact on this change in accounting policy resulted in recording a transitional adjustment to share capital and retained earnings of \$890. This adjustment reversed previous flow-through renunciation adjustments made through share capital and recorded the related tax affect. During the nine months ended September 30, 2010, under Canadian GAAP, the Company recorded the related tax affect of \$57 to share capital. Therefore, the Company adjusted the \$57 to share capital and deferred income tax.

(f) Income tax

Deferred income taxes have been adjusted to reflect the tax effect arising from the differences between IFRS and Canadian GAAP. The application of the IFRS adjustments for note 16 (a) through to (d) as at September 30, 2010 and December 31, 2010, resulted in an increase of \$860 to the deferred income tax liability. For the three and nine months ended September 30, 2010, deferred income tax expense increased by \$573 and \$1,526.

(g) Adjustments to the Company's Cash Flow Statement under IFRS

The reconciling items discussed above between Canadian GAAP and IFRS policies have no material impact on the cash flows generated by the Company.

CORPORATE INFORMATION

BOARD OF DIRECTORS

Stuart G. Clark ^{(1) (2) (3)}
Chairman of the Board
Independent Businessman
Calgary, Alberta

Allen J. Bey
Chief Executive Officer
Rock Energy Inc.
Calgary, Alberta

Malcolm T. D. Adams ^{(2) (4)}
Vice President
Corporate Development
Surge Energy Inc.
Calgary, Alberta

Kenneth H. F. Severs ⁽⁴⁾
President
Charob Resources Inc.
Calgary, Alberta

James K. Wilson ^{(2) (3)}
Managing Director
Walwil Resources Ltd.
Calgary, Alberta

William H. Slavin ^{(3) (4)}
Managing Director
ARC Financial Corp.
Calgary, Alberta

⁽¹⁾ Chairman of the Board

⁽²⁾ Member of the Audit Committee

⁽³⁾ Member of the Compensation,
Nomination and Governance
Committee

⁽⁴⁾ Member of the Reserves Committee

OFFICERS

Allen J. Bey
Chief Executive Officer

John H. Van de Pol
President and
Chief Financial Officer

Jeffrey G. Campbell
Senior Vice President and
Chief Operating Officer

Bryan P. Dozzi
Vice President, Business Development

Terry M. Manery
Vice President and Controller

AUDITORS
KPMG LLP

BANK

National Bank of Canada

ENGINEERING CONSULTANT
GLJ Petroleum Consultants Ltd.

SOLICITORS

Burnet, Duckworth & Palmer LLP

STOCK EXCHANGE LISTING: TSX
Stock Symbol: RE

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ABBREVIATIONS

bbl	barrel(s)	mbbls	thousand barrels
bcf	billion cubic feet	mboe	thousand barrels of oil equivalent
boe	barrels of oil equivalent	mboe/day	thousand barrels of oil equivalent per day
bps	basis points	mcf	thousand cubic feet
CDOR	Certificate of Deposit Offered Rate	mmcf	million cubic feet
GJ	gigajoule	mmbbls	million barrels
hectare	1 hectare is equal to 2.47 acres	mmbboe	million barrels of oil equivalent
km	kilometre	NGL	natural gas liquids
		WTI	West Texas Intermediate

 **rockenergy** INC.