

Management's Discussion and Analysis

Rock Energy Inc. ("Rock" or the "Company") is a publicly traded energy company engaged in the exploration for and the development and production of crude oil and natural gas, primarily in Western Canada. Rock's corporate strategy is to grow and develop an oil and natural gas exploration and production company through internal operations and acquisitions.

Rock evaluates its performance based on net income, field netback, funds from operations 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 natural gas industry to measure the contribution of the 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 natural gas industry to measure the capital costs incurred by the Company to find and bring reserves on-stream.

Rock faces competition in the oil and natural gas industry for resources, including technical personnel and third-party services, and capital financing. The Company is addressing these issues through the addition of personnel with the expertise to develop opportunities on existing lands and to 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 Management's Discussion and Analysis is dated March 12, 2009 and is management's assessment of Rock's historical, financial and operating results, together with future prospects, and should be read in conjunction with the audited consolidated financial statements of Rock for the year ended December 31, 2008.

BASIS OF PRESENTATION

Certain financial measures referred to in this discussion, such as funds from operations and funds from operations per share, are not prescribed by generally accepted accounting principles (GAAP). Funds from operations is a key measure that demonstrates the ability to generate cash to fund expenditures. Funds from operations is calculated by taking the cash provided by operations from the consolidated statement of cash flows and adding back changes in non-cash working capital. Funds from operations per share are calculated using the same methodology for determining net income per share. These non-GAAP 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 or other measures of financial performance calculated in accordance with GAAP. The reconciliation between funds from operations and cash flow from operations for the three months and years ended December 31, 2008 and 2007 is presented in the table below.

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	3 Months Ended 12/31/08	3 Months Ended 12/31/07
(\$thousands)				
Funds from operations	\$ 40,747	\$ 15,189	\$ 5,516	\$ 4,735
Changes in non-cash working capital	843	(1,035)	745	251
Cash flow from operations	\$ 41,590	\$ 14,154	\$ 6,261	\$ 4,986

Management uses certain industry benchmarks such as field netback to analyze financial and operating performance. Field netback has been calculated by taking oil and gas revenue less royalties, operating costs and transportation costs. This benchmark does not have a standardized meaning prescribed by GAAP and may not be comparable to similar measures presented by other companies. Management considers field netback as 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 oil at the ratio of six thousand cubic feet (mcf) of natural gas to one barrel (bbl) of 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 necessarily 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, future income taxes, wells drilled, 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.

GUIDANCE AND OUTLOOK

The Company issued guidance on November 13, 2008 for projected 2008 and 2009 results. The table below provides the guidance for 2008 with actual results.

2008 GUIDANCE

	2008 Guidance	Actual	Difference
2008 Production (boe/d)			
Annual	3,400-3,600	3,436	0%
Exit (December average)	4,300-4,500	4,055	(8)%
2008 Funds from Operations			
Annual	\$43 million	\$40.7 million	(5)%
Annual (per share)	\$1.66	\$1.57	(5)%
2008 Capital Budget			
Expenditures	\$52 million	\$50.2 million	(3)%
Gross wells drilled	34	33	(3)%
Total net debt at year-end	\$38 million	\$38.6 million	2%
Pricing (Fourth Quarter)			
Oil – WTI	US\$70.00/bbl	US\$58.73/bbl	(16)%
Natural gas – AECO	\$7.00/mcf	\$6.70/mcf	(4)%
US/CDN dollar exchange rate	0.85	0.825	(3)%

Production average for the year was within the guidance range; however, the exit rate was below guidance primarily as the compressor expansion at Elsworth in the West Central core area did not come on-stream until mid first quarter 2009 compared to our forecast start date of mid November 2008 and we elected to leave approximately 100 bbls/day of heavy oil shut-in for maintenance purposes given the low heavy oil price. Funds flow from operations was below guidance due to lower prices and production in the fourth quarter of 2008. Capital expenditures were lower than forecast as 1 (1.0 net) well at Saxon did not start drilling until the first quarter of 2009. As a result of lower funds from operations, partially offset by lower capital expenditures, debt levels were slightly above guidance levels.

Guidance for 2009 has been updated to reflect results from the winter drilling program, well performance and lower expected commodity prices. The table below updates the Company's previous guidance that was issued November 13, 2008.

2009 GUIDANCE

	2009 Previous Guidance	2009 Revised Guidance	Change
2009 Production (boe/d)			
Annual	4,100-4,300	3,200-3,400	(21)%
Exit	4,400-4,600	3,100-3,300	(29)%
2009 Funds from Operations			
Annual	\$33 million	\$17.5 million	(47)%
Annual – (per share)	\$1.28	\$0.68	(47)%
2009 Capital Budget			
Expenditures	\$37.5 million	\$15 million	(60)%
Gross wells drilled	35	12	(66)%
Total net debt at year-end	\$42.5 million	\$36.1 million	(15)%
Pricing (Annual Average)			
Oil – WTI	US\$70.00/bbl	US\$47.00/bbl	(33)%
Natural gas – AECO	Cdn\$7.00/mcf	Cdn\$5.00/mcf	(29)%
US/CDN dollar exchange rate	0.85	0.80	(6)%

The decline in commodity prices has caused Rock to significantly cut back on capital expenditures. If these commodity prices persist the Company anticipates drilling 12 (10.7 net) wells in 2009 of which 2 (1.3 net) wells were drilled in the first quarter of 2009. Furthermore wells that require servicing are likely to be delayed unless a short payout period can be achieved on the expected service expenditures. Rock anticipates acquiring land and seismic (current budget of \$1.8 million) in order to develop additional drilling inventory which can be accessed once commodity prices improve. Rock anticipates that Lloyd blend heavy oil prices need to approach \$50.00/bbl and natural gas prices need to exceed \$7.00/mcf in order to significantly expand our drilling activities. In the current environment Rock anticipates natural production declines and delayed well servicing will cause 2009 production to average approximately 3,300 boe/day with exit rates of approximately 3,200 boe/day. The combined reduction in commodity prices and production is expected to result in funds from operations for 2009 of approximately \$17.5 million (\$0.68 per basic share). Royalty rates are expected to average 15 percent in this price environment and after taking into account the new initiatives recently announced by the Alberta government (down from 26 percent in the previous forecast), operating costs are expected to average 5 percent higher than previously forecast at \$12.85/boe based on recent experience and net G&A expense of \$2.60/boe (up from \$2.00/boe in our previous guidance due to lower forecast production). Debt to funds from operations ratio is expected to be about 2.1 times on an annual basis, falling from a high of 2.9 times in the first quarter down to 1.7 times in the fourth quarter. Management believes in the current commodity price cycle, capital expenditures should be less than funds from operations, with capital expenditures directed at preserving the reserve base. We will continue to monitor debt availability, funds from operations and capital expenditures in order to chart a prudent course of action and stay within our borrowing capacity.

PRODUCTION AND PRICES

PRODUCTION BY PRODUCT

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Natural gas (mcf/d)	10,048	4,261	136%	11,731	6,372	84%
Light and medium oil (bbls/d)	193	215	(10)%	169	206	(18)%
Heavy oil (bbls/d)	1,329	1,194	11%	1,537	1,323	16%
NGL (bbls/d)	239	79	203%	298	81	268%
Total (boe/d) (6:1)	3,436	2,198	56%	3,959	2,672	48%

PRODUCTION BY AREA

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
West Central Alberta (boe/d)	1,722	642	168%	2,090	1,041	101%
Plains (boe/d)	1,362	1,196	14%	1,563	1,325	18%
Other (boe/d)	352	360	(2)%	306	306	0%
Total (boe/d) (6:1)	3,436	2,198	56%	3,959	2,672	48%

Production increased 56 percent for the year ended December 31, 2008 over the prior year due to new natural gas and NGL production from Saxon in the West Central core area, production acquired and new drilling at Elmworth, and increased heavy oil production. New production at Saxon (West Central core area) reflects our efforts in the deep basin area over the last several years. Land and seismic was acquired in the summer of 2007 and the first wells were drilled and tied-in during the 2007-08 winter drilling season resulting in new production coming on-stream in May 2008. Rock still has 4-6 additional locations in inventory. The Company's Elmworth property in the West Central core area was acquired with the Greenbank acquisition at the end of the third quarter of 2007. Production at the time of acquisition was approximately 500 boe/day (92 percent natural gas) and through drilling this past summer has grown to more than 700 boe/day. Start up of a compressor expansion scheduled for mid November 2008 was delayed until early February 2009 and is expected to add additional production. Heavy oil production increases were driven by drilling which primarily occurred in third quarter of 2008. Of the 18 (18.0 net) cased wells drilled, 14 (14.0 net) are producing at expected rates or better, 1 (1.0 net) is waiting on recompletion and 3 (3.0 net) have declined significantly within months of production and are currently shut-in.

Production increased by 48 percent in the fourth quarter of 2008 from the same period last year and reached 4,000 boe/day during the quarter due to the Company's drilling activity at Saxon and Elmworth in the West Central core area and heavy oil in the Plains core area. Later in the fourth quarter and continuing in the first quarter of 2009 the Company has delayed servicing of some heavy oil wells and delayed the drilling of any additional wells subsequent to the Saxon and Elmworth wells that were drilled in January 2009. As a result current production is approximately 3,700 boe/day. New production from the Elmworth drills plus the start up of additional compression at Elmworth will help offset production declines and delayed servicing.

PRODUCT PRICES

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Realized Product Prices						
Natural gas (\$/mcf)	8.72	6.96	25%	7.27	6.64	9%
Light and medium oil (\$/bbl)	95.86	70.69	36%	57.20	81.66	(30)%
Heavy oil (\$/bbl)	71.58	41.18	74%	40.17	42.56	(6)%
NGL (\$/bbl)	74.15	60.00	24%	45.78	67.81	(32)%
Combined average (\$/boe) (6:1)	63.73	44.93	42%	43.02	45.26	(5)%
Average Reference Prices						
Natural gas – Henry Hub Daily Spot (US\$/mmbtu)	8.88	6.98	27%	6.47	7.01	(8)%
Natural gas – AECO C Daily Spot (\$/mcf)	8.16	6.45	27%	6.70	6.15	9%
Oil – WTI Cushing, Oklahoma (US\$/bbl)	99.65	72.31	38%	58.73	90.68	(35)%
Oil – Edmonton Light (\$/bbl)	102.16	76.35	34%	63.21	86.42	(27)%
Heavy oil – Lloydminster blend (\$/bbl)	82.87	51.63	61%	48.61	55.49	(12)%
US/CDN\$ exchange rate	0.943	0.935	1%	0.825	1.019	(19)%

The first three quarters of 2008 are in contrast to the last quarter of 2008 with respect to commodity price realizations. Rock experienced very strong pricing in the former periods and continual deterioration in prices, particularly for oil based products, in the latter period. The Company realized its lowest prices over the year in December 2008 of \$34.60/boe versus the highest realized prices of \$89.57/boe in July 2008.

Heavy oil prices were significantly higher for the year ended 2008 compared to 2007 based on the strength of the first three quarters while prices in the fourth quarter of 2008 were 6 percent lower than the same period in 2007. The drop in WTI prices in the fourth quarter were partially offset by narrower price differentials to Edmonton par pricing (36 percent in Q4 2008 versus 51 percent in Q4 2007). WTI prices are currently around US\$45/bbl and heavy oil differentials appeared to have narrowed from December 2008 levels resulting in a current estimated heavy oil wellhead price of \$35/bbl (compared to \$19/bbl for December 2008).

Canadian natural gas prices for the year and fourth quarter of 2008 were higher than 2007. Similar to oil, natural gas prices were higher for the first three quarters of 2008 as higher U.S. prices more than offset the stronger Canadian dollar during this period. However in the fourth quarter of 2008, the weaker Canadian dollar and narrower pricing differential more than offset the decline in U.S. gas prices resulting in a higher Canadian gas price than in the fourth quarter of 2007. Late in the fourth quarter and continuing into 2009, natural gas prices (both in the U.S. and Canada) have continued to decline as the combination of reduced industrial demand due to a poor economy and increased U.S. production from shale gas has more than offset the effect of a colder winter and the lack of liquefied natural gas imports. As a result storage levels compared to last year have gone from a year over year deficit entering the heating season in November 2008 to a surplus currently. Canadian natural gas prices at AECO are currently about \$4.25/mcf, approximately 35 percent lower than the \$6.60/mcf for December 2008. Rock has not hedged any commodity prices at this time.

REVENUE

The vast majority of the Company's revenue is derived from oil and natural gas operations. Other income is primarily royalty interest revenue.

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Natural gas	\$ 32,052	\$ 10,830	196%	\$ 7,845	\$ 3,890	102%
Light and medium oil	6,780	5,538	22%	889	1,547	(43)%
Heavy oil	34,813	17,951	94%	5,681	5,180	10%
NGL	6,493	1,724	277%	1,255	507	148%
	80,138	36,042	122%	15,670	11,124	41%
Other revenue	\$ 138	\$ 79	75%	\$ 76	\$ 12	533%

Oil and natural gas revenue more than doubled for the year ended December 31, 2008 over 2007 due to higher realized prices and production levels. For the fourth quarter of 2008 oil and natural gas revenue increased by 41 percent from the same period in 2007 as higher production and higher natural gas prices more than offset the decrease in oil prices.

ROYALTIES

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Royalties	\$ 17,094	\$ 7,035	143%	\$ 3,366	\$ 2,017	67%
As a percentage of oil and natural gas revenue	21.3%	19.5%	9%	21.6%	18.1%	19%
Per boe (6:1)	\$ 13.59	\$ 8.77	55%	\$ 9.24	\$ 8.21	13%

Royalties increased for the year and quarter ended December 31, 2008 over the prior year periods due to higher production levels and higher prices. Alberta Royalty Tax Credits (ARTC), which was cancelled effective January 1, 2007, impacted the fourth quarter of both 2008 and 2007. The fourth quarter of 2008 included a charge of \$72 as a result of an ARTC audit on previously acquired properties and the fourth quarter of 2007 included a \$459 benefit as companies with off-calendar (non-December 31) tax year-ends were allowed to benefit from a full calendar year of ARTC. Without the ARTC benefit the royalty rates for 2007 would have been 22.2 percent for the quarter and 20.8 percent for the year.

OPERATING EXPENSES

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Operating expense	\$ 16,456	\$ 9,505	73%	\$ 5,207	\$ 2,889	80%
Transportation costs	905	420	114%	251	130	89%
	17,361	9,925	75%	5,458	3,019	81%
Per boe (6:1)	\$ 13.81	\$ 12.37	11%	\$ 14.99	\$ 12.28	22%

Operating expenses for the year and quarter ended December 31, 2008 increased over 2007 primarily due to higher production and per unit costs. Heavy oil operations experienced increased cost pressures in 2008 as a result of higher fuel, trucking and service costs compared to the prior year. Fourth quarter 2008 heavy oil operating costs were also negatively impacted by extremely cold weather in December 2008 which led to higher fuel usage. As a result heavy oil per boe operating costs increased in 2008 to \$17.60/boe (\$18.42/boe for the fourth quarter of 2008) from \$12.90/boe in 2007 (\$13.61/boe for the fourth quarter of 2007). West Central operations tend to have lower operating costs, particularly at Elsworth, which helps lower the corporate average per boe. Transportation costs increased as a result of the properties acquired at the end of third quarter of 2007.

GENERAL AND ADMINISTRATIVE (G&A) EXPENSE

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Gross	\$ 4,924	\$ 4,791	3%	\$ 1,421	\$ 1,593	(11)%
Per boe (6:1)	3.92	5.97	(34)%	3.90	6.48	(40)%
Capitalized	1,592	2,004	(21)%	400	589	(32)%
Per boe (6:1)	1.27	2.50	(49)%	1.10	2.39	(54)%
Overhead recoveries	96	48	100%	30	49	(39)%
Per boe (6:1)	0.08	0.06	33%	0.08	0.21	(62)%
Net	3,236	2,739	18%	991	955	4%
Per boe (6:1)	2.57	3.41	(25)%	2.72	3.88	(30)%

G&A expense increased on an absolute basis in 2008 over 2007 but declined on a per boe basis. Costs increased due to the higher overall cost environment as well as consulting costs associated with higher activity levels. In the fourth quarter of 2008 the Company recorded \$59 of bad debt expense related to prior acquisitions. Rock capitalizes certain G&A expenses based on personnel involved in exploration and development initiatives, including salaries and related overhead costs.

INTEREST EXPENSE

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Interest expense	\$ 1,565	\$ 1,157	35%	\$ 331	\$ 417	(21)%
Per boe (6:1)	\$ 1.24	\$ 1.44	(14)%	\$ 0.91	\$ 1.70	(46)%

Interest expense increased for the year ended 2008 over the 2007 period due to higher average bank debt (\$31.4 million for 2008 versus \$18.5 million for 2007), partially offset by lower interest rates. For the fourth quarter of 2008 lower average interest rates more than offset the increase in average bank debt (\$32.6 million for fourth quarter of 2008 versus \$26.2 million for the fourth quarter of 2007) resulting in lower interest expense. Bank debt increased as capital expenditures, excluding acquisitions, exceeded funds from operations and were funded through the Company's bank facility.

DEPLETION, DEPRECIATION AND ACCRETION (DD&A)

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Depletion and depreciation expense	\$ 27,849	\$ 13,989	99%	\$ 7,734	\$ 5,021	54%
Per boe (6:1)	\$ 22.15	\$ 17.44	27%	\$ 21.24	\$ 20.42	4%
Accretion expense	\$ 260	\$ 154	69%	\$ 71	\$ 48	48%
Per boe (6:1)	\$ 0.21	\$ 0.19	11%	\$ 0.19	\$ 0.20	(5)%

Depletion and depreciation expense for the year and quarter ended December 31, 2008 increased over the prior year periods due to higher production and higher cost reserve additions in 2008. The Company spent relatively more capital in the West Central core area (including approximately \$14 million of infrastructure costs) which tends to have higher cost reserve additions than the Plains core area.

The Company's asset retirement obligation (ARO) represents the present value of estimated future costs to be incurred to abandon and reclaim the Company's wells and facilities. The discount rate used is 8 percent.

Accretion represents the change in the time value of ARO. The underlying ARO may be increased over a period based on new obligations incurred from drilling wells, constructing facilities or acquiring operations. Similarly, this obligation can also be reduced as a result of abandonment work undertaken and reducing future obligations. During the year ended December 31, 2008 capital programs net of dispositions increased the underlying ARO by \$491 (December 31, 2007 – \$1,592) and actual expenditures on abandonments were \$94 (December 31, 2007 – \$nil).

INCOME TAX

The Company pays Saskatchewan resource capital taxes based on its production in the province. Rock does not have current income tax payable and does not expect to pay current income taxes in 2009 as the Company and its subsidiaries had estimated resource and other pools available at December 31, 2008 (after the allocation of deferred partnership income) of approximately \$114.7 million as set out below:

CEE	\$ 28.2 million
CDE	34.6 million
COGPE	10.5 million
UCC	29.5 million
Loss carry-forwards	10.9 million
Other	1.0 million
Total	\$ 114.7 million

FUNDS FROM OPERATIONS AND NET INCOME/(LOSS)

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Funds from operations	\$ 40,747	\$ 15,189	168%	\$ 5,516	\$ 4,735	16%
Per boe (6:1)	\$ 32.40	\$ 18.93	71%	\$ 15.15	\$ 19.26	(21)%
Per share:						
Basic	\$ 1.57	\$ 0.72	118%	\$ 0.21	\$ 0.18	17%
Diluted	\$ 1.57	\$ 0.72	118%	\$ 0.21	\$ 0.18	17%
Net income (loss)	\$ 1,891	\$ 561	237%	\$ (2,083)	\$ 290	(818)%
Per boe (6:1)	\$ 1.50	\$ 0.70	114%	\$ (5.72)	\$ 1.18	(585)%
Per share:						
Basic	\$ 0.07	\$ 0.03	133%	\$ (0.08)	\$ 0.01	(900)%
Diluted	\$ 0.07	\$ 0.03	133%	\$ (0.08)	\$ 0.01	(900)%
Weighted average shares outstanding:						
Basic	25,885	21,239	22%	25,900	25,847	0%
Diluted	25,923	21,239	22%	25,900	25,847	0%

The Company issued 6.1 million shares at September 28, 2007 to acquire Greenbank Energy Ltd. which is the primary reason for the increase in weighted average shares outstanding for 2008 versus 2007.

Funds from operations for the year ended December 31, 2008 more than doubled over 2007 as production and price increases more than offset the increase in royalties, operating, G&A and interest costs. On a per boe basis, 2008 funds from operations increased by 71 percent from 2007 primarily for the same reasons except for the reduction in G&A and interest costs. For the fourth quarter of 2008 funds from operations increased by 16 percent on an absolute basis from the prior year's periods primarily as the increase in production more than offset the increase in royalties and G&A costs and decreases in prices. On a per boe basis funds from operations for the fourth quarter of 2008 decreased 21 percent from the prior year due to lower prices, higher royalties and operating costs, partially offset by a decrease in G&A and interest costs. On a per share basis, funds from operations increased 118 percent in 2008 versus 2007 and increased 17 percent in the fourth quarter of 2008 over the same quarter in 2007. The Company posted a 237 percent increase in net income for the year ended 2008 versus 2007 despite higher depletion expense combined with the write-off of goodwill in the third quarter. Higher depletion expense caused Rock to post a net loss for the fourth quarter of 2008 compared to net income for the prior year period.

CAPITAL EXPENDITURES

(\$thousands)	12 Months Ended 12/31/08	12 Months Ended 12/31/07	Change	3 Months Ended 12/31/08	3 Months Ended 12/31/07	Quarterly Change
Land	\$ 5,688	\$ 3,723	52%	\$ 887	\$ 457	94%
Seismic	1,614	1,359	19%	487	56	777%
Drilling and completions	28,004	15,799	68%	8,407	4,801	51%
Facilities & natural gas gathering systems ⁽¹⁾	14,095	1,584	1,932%	(88)	1,431	(113)%
Capitalized G&A	1,592	2,004	(21)%	400	589	(32)%
Total operations	\$ 50,993	\$ 24,469	108%	\$ 10,093	\$ 7,334	38%
Property acquisitions (dispositions) ⁽²⁾	(1,243)	28,127	(104)%	nil	nil	n/a
Well site facilities inventory	344	94	266%	(833)	(19)	4,381%
Office equipment	78	1,012	(92)%	(4)	173	(102)%
Total (net of acquisitions and dispositions)	\$ 50,172	\$ 53,702	(7)%	\$ 9,256	\$ 7,488	24%

(1) Note items have been reclassified from drilling and completion costs to facilities and natural gas gathering systems to better reflect spending categories.

(2) Property acquisitions for 2007 have been restated from the third quarter 2007 report to be presented as the amount allocated to property, plant and equipment versus the consideration paid.

Capital expenditures for operations more than doubled for the year ended December 31, 2008 compared to 2007 as Rock drilled 33 (24.3 net) wells in 2008 versus 16 (12.2 net) wells in 2007. Facilities and natural gas gathering expenditures also increased due to the compression and pipeline facilities that were constructed and brought on-stream at Saxon in the first half of 2008 and due to the completion of tie-in operations in the Musreau and Kakwa areas in the first quarter of 2008.

Plains core area drilling is broken down as follows over the last two years:

	2008	2007
Heavy oil	18 (18.0 net)	8 (8.0 net)
Natural gas	nil	1 (0.9 net)
Dry hole	1 (1.0 net)	1 (1.0 net)
Total	19 (19.0 net)	10 (9.9 net)

All of the heavy oil wells were placed on production in 2008 which increased production from 1,140 bbl/day in January 2008 to 1,440 bbl/day in December 2008.

West Central core area drilling is broken down as follows over the last two years:

	2008	2007
Saxon	1 (1.0 net)	1 (1.0 net)
Tony Creek	2 (0.9 net)	nil
Girouxville	2 (0.9 net)	nil
Musreau/Kakwa	1 (0.2 net)	3 (0.9 net)
Markerville	1 (0.2 net)	nil
Elmworth	7 (2.1 net)	1 (0.3 net)
Dry hole	nil	1 (0.1 net)
Total	14 (5.3 net)	6 (2.3 net)

Rock operated 5 (2.5 net) of the West Central wells in 2008 compared to 2 (1.3 net) wells in 2007. All of the wells drilled in 2008 were brought on-stream in 2008 except for 2 (0.6 net) Elmworth wells which were delayed until the first quarter of 2009 behind a compression expansion. West Central core area production has increased from 1,070 boe/day in January 2008 to 2,300 boe/day in December 2008 with the majority of the production increase coming from Saxon and Elmworth.

Land and seismic expenditures increased in 2008 versus 2007 as the Company added undeveloped acreage and acquired seismic at Elmworth and Saxon in the West Central core area and in the Plains core area. Total net capital expenditures decreased to \$50.2 million in 2008 versus \$53.7 million in 2007 as minor non-core property dispositions were completed in 2008 versus the acquisition of Greenbank in 2007.

LIQUIDITY AND CAPITAL RESOURCES

Rock's current approved capital budget for 2009 projects spending of \$15 million. In 2009 funds from operations is expected to be approximately \$17.5 million. Approximately 30 percent of the capital budget is expected to be spent in the first four months of the year with the majority of these costs already incurred at Saxon. The balance of the budget is expected to be spent after spring break-up with almost half it being spent in the third quarter of 2009. At year-end 2008 Rock had debt of \$39 million against bank lines of \$51 million. The Company's debt-to-funds from operations ratio was 0.9:1 at year-end based on annual 2008 results; however, this ratio has risen to 1.75:1 based on annualized fourth quarter funds from operations. The ratio is expected to rise again in 2009 to approximately 2.9:1 in the first quarter but falling to 1.7:1 in the fourth quarter and averaging 2.1:1 on an annual basis based on current projections.

The projected debt-to-funds from operations ratio is higher than our target of 1.5:1 as commodity prices have fallen significantly since the third quarter of 2008 and Rock's wellhead prices have decreased over 50 percent from a high of \$89.57/boe in July 2008 to \$34.60/boe in December 2008. As a result, we plan to restrict capital expenditures to be less than funds from operations which should reduce bank debt from year-end 2008 levels. Should commodity prices fall below our current projections, we would look at reducing capital expenditures further and expect to shut-in operations that are not producing positive field netback.

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 oil and natural gas assets and the credit currently available is \$51 million. 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. The facility also bears a standby charge for undrawn 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. The next annual review for the facility is scheduled to be completed by April 30, 2009. As at March 11, 2009 approximately \$32.8 million was drawn under the facility.

SELECTED ANNUAL DATA

The following table provides selected annual information for Rock:

	12 Months Ended 12/31/08	12 Months Ended 12/31/07	12 Months Ended 12/31/06
Production (boe/d)	3,436	2,198	2,098
Oil and natural gas revenues (\$000)	\$ 80,138	\$ 36,042	\$ 33,156
Average realized price (\$/boe)	\$ 63.73	\$ 44.93	\$ 43.27
Royalties (\$/boe)	\$ 13.59	\$ 8.77	\$ 8.98
Operating expense (\$/boe)	\$ 13.81	\$ 12.37	\$ 12.08
Field netback (\$/boe)	\$ 36.33	\$ 23.79	\$ 22.21
Net G&A expense (\$000)	\$ 3,236	\$ 2,739	\$ 2,278
Stock-based compensation (\$000)	\$ 1,158	\$ 931	\$ 1,188
Funds from operations (\$000)	\$ 40,747	\$ 15,189	\$ 13,867
Per share – basic	\$ 1.57	\$ 0.72	\$ 0.71
Per share – diluted	\$ 1.57	\$ 0.72	\$ 0.71
Net income (loss)	\$ 1,891	\$ 561	\$ (884)
Per share – basic	\$ 0.07	\$ 0.03	\$ (0.05)
Per share – diluted	\$ 0.07	\$ 0.03	\$ (0.05)
	As at 12/31/08	As at 12/31/07	As at 12/31/06
Total assets	\$ 150,510	\$ 130,495	\$ 85,380
Total liabilities	\$ 61,488	\$ 44,301	\$ 24,901

SELECTED QUARTERLY DATA

The following table provides selected quarterly information for Rock:

	3 Months Ended 12/31/08	3 Months Ended 09/30/08	3 Months Ended 06/30/08	3 Months Ended 03/31/08	3 Months Ended 12/31/07	3 Months Ended 09/30/07	3 Months Ended 06/30/07	3 Months Ended 03/31/07
Production (boe/d)	3,959	3,526	3,454	2,798	2,672	1,965	2,036	2,114
Oil and natural gas revenues (\$000)	\$ 15,670	\$ 24,424	\$ 24,756	\$ 15,294	\$ 11,124	\$ 8,106	\$ 8,279	\$ 8,553
Average realized price (\$/boe)	\$ 43.02	\$ 75.27	\$ 78.80	\$ 60.06	\$ 45.26	\$ 44.85	\$ 44.66	\$ 44.84
Royalties (\$/boe)	\$ 9.24	\$ 16.02	\$ 16.53	\$ 13.11	\$ 8.21	\$ 9.18	\$ 9.23	\$ 8.66
Operating expense (\$/boe)	\$ 14.99	\$ 13.08	\$ 14.26	\$ 12.48	\$ 12.28	\$ 12.38	\$ 12.10	\$ 12.75
Field netback (\$/boe)	\$ 18.79	\$ 46.17	\$ 48.01	\$ 34.47	\$ 24.77	\$ 23.29	\$ 23.33	\$ 23.43
Net G&A expense (\$000)	\$ 991	\$ 687	\$ 765	\$ 793	\$ 955	\$ 528	\$ 530	\$ 726
Stock-based compensation (\$000)	\$ 239	\$ 312	\$ 315	\$ 292	\$ 216	\$ 207	\$ 241	\$ 267
Funds from operations (\$000)	\$ 5,516	\$ 13,906	\$ 13,785	\$ 7,540	\$ 4,735	\$ 3,397	\$ 3,536	\$ 3,521
Per share – basic	\$ 0.21	\$ 0.54	\$ 0.53	\$ 0.29	\$ 0.18	\$ 0.17	\$ 0.18	\$ 0.18
Per share – diluted	\$ 0.21	\$ 0.53	\$ 0.53	\$ 0.29	\$ 0.18	\$ 0.17	\$ 0.18	\$ 0.18
Net income (loss) (\$000)	\$ (2,083)	\$ (1,266)	\$ 4,020	\$ 1,220	\$ 290	\$ 15	\$ (117)	\$ 373
Per share – basic	\$ (0.08)	\$ (0.05)	\$ 0.16	\$ 0.05	\$ 0.01	\$ 0.00	\$ (0.01)	\$ 0.02
Per share – diluted	\$ (0.08)	\$ (0.05)	\$ 0.15	\$ 0.05	\$ 0.01	\$ 0.00	\$ (0.01)	\$ 0.02
Capital expenditures (\$000)	\$ 9,256	\$ 18,174	\$ 6,345	\$ 16,398	\$ 7,488	\$ 8,367	\$ 2,552	\$ 7,184
	As at 12/31/08	As at 09/30/08	As at 06/30/08	As at 03/31/08	As at 12/31/07	As at 09/30/07	As at 06/30/07	As at 03/31/07
Total debt (\$000) ⁽¹⁾	\$ 38,622	\$ 34,903	\$ 30,528	\$ 37,933	\$ 29,072	\$ 26,589	\$ 15,268	\$ 16,242

(1) Total debt includes bank debt and any working capital deficiency.

Production for the fourth quarter of 2008 increased 12 percent over the preceding quarter and has continued to grow since the third quarter of 2007 mostly due to our drilling program and in part to the Greenbank acquisition completed at the end of the third quarter of 2007. During the course of 2008 the Company has been successful at increasing heavy oil production in our Plains core area and natural gas and NGL production in our West Central core area, particularly at Saxon and Elsworth. The field netback for the first three quarters of 2008 almost doubled levels achieved in 2007 primarily due to strong commodity prices. The rapid decline of commodity prices in the fourth quarter of 2008 caused the field netback to fall below 2007 levels. Royalties reflected increases in revenues but remained fairly constant at about a 21 percent average rate. Operating costs pressures were experienced, particularly for trucking, fuel, and well servicing costs for heavy oil, and were higher on a per boe basis. G&A expenses are generally higher in the fourth quarters of any particular year due to costs associated with year-end reporting. In 2008 G&A expenses were higher than in 2007 due to increased activity levels but lower on a per boe basis. Funds from operations (on an absolute and per share basis) improved with higher production and stronger field netbacks (for the first three quarters of 2008). Net income (on an absolute and per share basis) improved in the first half of 2008 over 2007 levels based on higher funds from operations. In the last half of 2008 the Company reported net losses as a result of a \$5.7 million write down of goodwill in the third quarter due to equity market conditions and higher depletion expenses.

Net capital expenditures (excluding acquisitions and dispositions) essentially doubled in 2008 over 2007 levels due to increased drilling activity, land acquisitions and seismic operations in both our core areas. Negative working capital also increased in 2008 over the previous quarter as capital spending exceeded funds from operations in all quarters of 2008 except the second quarter due to spring break-up conditions.

RESERVES

Rock's reserves have been independently evaluated by GLJ Petroleum Consultants Ltd. (GLJ) at year-end 2008. This is the fifth year that GLJ has evaluated the Company's reserves. The reserves as at December 31, 2008 and 2007 have been evaluated in accordance with *National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101)*. The following tables provide a reconciliation of the Company's reserves between year-end 2008 and year-end 2007 on a gross basis (before deducting royalties and without including any royalty interest) (gross interest).

Rock's gross interest reserves at year-end 2008 are 5.8 million boe of proved reserves and 10.2 million boe of proved plus probable reserves. The growth in gross interest reserves resulted from oil and natural gas operations (net of revisions) which added 1.8 million boe of proved reserves and 2.1 million boe of proved plus probable reserves. Proved producing reserves have increased to 46 percent of proved plus probable reserves on a gross interest basis at year-end 2008 from 38 percent at year-end 2007 as a significant amount of capital was spent developing proved reserves and proving up probable reserves, particularly in the West Central core area. The breakdown of reserves on a commodity basis has changed slightly on a proved plus probable basis from 2007 to 2008 with heavy oil now comprising 46 percent of reserves (up from 40 percent in 2007) and natural gas comprising 45 percent of reserves (down from 50 percent in 2007). During 2008 the Company sold 0.05 million boe of proved and 0.07 million boe of proved plus probable gross interest reserves.

RESERVES RECONCILIATION

The following table is a reconciliation of Rock's gross interest reserves at December 31, 2008 using GLJ's forecast pricing and cost estimates as at December 31, 2008.

RECONCILIATION OF COMPANY GROSS INTEREST RESERVES BY PRINCIPAL PRODUCT TYPE (FORECAST PRICES AND COSTS)

Factors	Light and Medium Oil		NGL		Heavy Oil		Natural Gas		Total Oil Equivalent	
	Proved (mbls)	Proved Plus	Proved (mbls)	Proved Plus	Proved (mbls)	Proved Plus	Proved (mmcf)	Proved Plus	Proved (mboe)	Proved Plus
		Probable (mbls)		Probable (mbls)		Probable (mmcf)		Probable (mboe)		
December 31, 2007	383	572	207	360	2,275	3,764	14,717	27,677	5,318	9,309
Additions ⁽¹⁾	0	0	48	67	1,000	1,741	2,487	3,589	1,462	2,406
Technical revisions ⁽²⁾	(29)	(115)	227	230	(185)	(346)	2,068	(8)	359	(231)
Acquisitions	0	0	0	0	0	0	0	0	0	0
Dispositions	(0)	(0)	(2)	(2)	0	0	(309)	(418)	(53)	(72)
Production	(71)	(71)	(88)	(88)	(486)	(486)	(3,667)	(3,667)	(1,258)	(1,258)
December 31, 2008	284	386	392	567	2,603	4,673	15,295	27,173	5,828	10,154

(1) Additions include discoveries, extensions, infill drilling and improved recovery.

(2) Technical revisions include technical revisions and economic factors.

Note: Figures may not add due to rounding; mbl=1,000 bbl, mmcf=1,000 mcf, mboe = 1,000 boe.

RESERVES AND NET PRESENT VALUE (FORECAST PRICES AND COSTS)

The following tables summarize Rock's remaining gross interest reserves volumes along with the value of future net revenue utilizing GLJ's forecast pricing and cost estimates as at December 31, 2008.

RESERVES

Reserves Category	Light and Medium Oil (mbl)	NGL (mbl)	Heavy Oil (mbl)	Natural Gas (mmcf)	Total Oil Equivalent (mboe)
Proved					
Proved producing	263	335	1,963	12,779	4,692
Proved non-producing	20	12	156	1,170	383
Proved undeveloped	0	44	485	1,345	753
Total proved	283	392	2,603	15,295	5,828
Probable additional	103	175	2,070	11,878	4,327
Total proved plus probable	386	567	4,673	27,173	10,154

Note: Figures may not add due to rounding; mbl=1,000 bbl, mmcf=1,000 mcf, mboe = 1,000 boe.

NET PRESENT VALUE OF FUTURE NET REVENUE

Reserves Category	Before Income Taxes Discounted at (% per year)					After Income Taxes Discounted at (% per year)				
	0	5	10	15	20	0	5	10	15	20
Proved										
Proved producing	135,106	114,195	99,586	88,764	80,395	129,769	110,505	96,923	86,779	78,876
Proved non-producing	10,106	7,522	5,965	4,909	4,141	7,702	5,692	4,523	3,744	3,183
Proved undeveloped	13,657	10,361	8,031	6,326	5,043	10,175	7,504	5,643	4,299	3,300
Total proved	158,870	132,077	113,582	100,000	89,579	147,646	123,701	107,089	94,822	85,538
Probable additional	116,782	83,892	63,884	50,497	40,955	87,107	61,954	46,686	36,501	29,089
Total proved plus probable	275,652	215,969	177,466	150,496	130,534	234,753	185,655	153,775	131,323	114,627

Note: Figures may not add due to rounding.

PRICING ASSUMPTIONS

The following benchmark prices, inflation rates and exchange rates were used by GLJ for the forecast prices and costs evaluation.

SUMMARY OF PRICING AND COST RATE ASSUMPTIONS AT DECEMBER 31, 2008 – FORECAST PRICES AND COSTS

Year	Oil				NGL				Natural Gas		Cost Inflation Rate (%/year)
	Edmonton WTI Cushing (US\$/bbl)	Edmonton Reference Price (\$/bbl)	Cromer Medium 29° API (\$/bbl)	Hardisty Heavy 12° API (\$/bbl)	Edmonton Propane (\$/bbl)	Edmonton Butane (\$/bbl)	Edmonton Pentane (\$/bbl)	Ethane (\$/bbl)	AECO-C (\$/mcf)	US\$/Cdn\$ Exchange Rate	
2009	57.50	68.61	59.00	43.10	43.22	52.14	69.98	25.55	7.58	0.825	2
2010	68.00	78.94	68.68	49.76	49.73	61.57	80.52	26.80	7.94	0.850	2
2011	74.00	83.54	73.52	54.35	52.63	65.16	85.21	28.19	8.34	0.875	2
2012	85.00	90.02	80.01	59.23	57.28	70.92	92.74	29.43	8.70	0.925	2
2013	92.01	95.91	84.40	62.54	60.42	74.81	97.82	30.27	8.95	0.950	2
2014	93.85	97.84	86.10	63.82	61.64	76.32	99.80	30.94	9.14	0.950	2
2015	95.73	99.82	87.84	65.13	62.89	77.86	101.81	31.62	9.34	0.950	2
2016	97.64	101.83	89.61	66.46	64.15	79.43	103.87	32.31	9.54	0.950	2
2017	99.59	103.89	91.42	67.83	65.45	81.03	105.97	33.02	9.75	0.950	2
2018	101.59	105.99	93.27	69.22	66.77	82.67	108.10	33.74	9.95	0.950	2
2019+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	0.950	2

FINDING, DEVELOPMENT AND ACQUISITION COSTS

The following table summarizes Rock's finding, development and acquisition costs for the years ended December 31, 2008, 2007 and 2006, including future development costs.

	12 months ended Dec. 31, 2008	12 months ended Dec. 31, 2007	12 months ended Dec. 31, 2006	3 Year Cumulative Total
Oil and Natural Gas Operations:				
Proved finding and development costs				
Capital expenditures ⁽¹⁾ (\$000)	\$ 50,939	\$ 24,163	\$ 32,907	\$ 108,009
Change in future capital costs (\$000)	(2,948)	3,501	2,939	3,492
Total capital (\$000)	\$ 47,991	\$ 27,664	\$ 35,846	\$ 111,501
Reserve additions ⁽²⁾ (mboe)	1,462	949	2,181	4,592
Proved finding and development costs (\$/boe)	\$ 32.82	\$ 29.15	\$ 16.44	\$ 24.28
Proved plus probable finding and development costs				
Capital expenditures ⁽¹⁾ (\$000)	\$ 50,939	\$ 24,163	\$ 32,907	\$ 108,009
Change in future capital costs (\$000)	3,106	3,930	7,986	15,022
Total capital (\$000)	\$ 54,045	\$ 28,093	\$ 40,893	\$ 123,031
Reserve additions ⁽²⁾ (mboe)	2,406	1,506	3,624	7,536
Proved plus probable finding and development costs (\$/boe)	\$ 22.46	\$ 18.66	\$ 11.28	\$ 16.33
Acquisitions/Dispositions:				
Proved finding and development costs – acquisitions (dispositions)				
Capital expenditures ⁽¹⁾ (\$000)	\$ (1,190)	\$ 28,524	\$ (30,878)	\$ (3,544)
Change in future capital costs (\$000)	(17)	4,136	(2,400)	1,719
Total capital (\$000)	\$ (1,207)	\$ 32,660	\$ (33,278)	\$ (1,825)
Reserve additions (mboe)	(53)	971	(1,042)	(125)
Proved finding and development costs (\$/boe)	\$ 22.59	\$ 33.64	\$ 31.94	\$ 14.65
Proved plus probable finding and development costs – acquisitions (dispositions)				
Capital expenditures ⁽¹⁾ (\$000)	\$ (1,190)	\$ 28,524	\$ (30,878)	\$ (3,544)
Change in future capital costs (\$000)	(17)	11,417	(2,400)	9,000
Total capital (\$000)	\$ (1,207)	\$ 39,941	\$ (33,278)	\$ 5,456
Reserve additions (mboe)	(72)	1,898	(1,406)	419
Proved plus probable finding and development costs (\$/boe)	\$ 16.69	\$ 21.05	\$ 23.67	\$ 13.01
Total Activities:				
Proved finding and development costs				
Capital expenditures ⁽¹⁾ (\$000)	\$ 49,750	\$ 52,687	\$ 2,029	\$ 104,465
Change in future capital costs (\$000)	(2,965)	7,637	539	5,211
Total capital (\$000)	\$ 46,785	\$ 60,324	\$ 2,568	\$ 109,676
Reserve additions ⁽³⁾ (mboe)	1,768	1,643	1,279	4,690
Total proved finding and development costs (\$/boe)	\$ 26.46	\$ 36.72	\$ 2.01	\$ 23.39
Proved plus probable finding and development costs				
Capital expenditures ⁽¹⁾ (\$000)	\$ 49,750	\$ 52,687	\$ 2,029	\$ 104,465
Change in future capital costs (\$000)	3,089	15,347	5,586	24,022
Total capital (\$000)	\$ 52,839	\$ 68,034	\$ 7,615	\$ 128,487
Reserve additions ⁽³⁾ (mboe)	2,103	2,786	2,153	7,042
Total proved plus probable finding and development costs (\$/boe)	\$ 25.13	\$ 24.42	\$ 3.54	\$ 18.24

(1) Capital expenditures include capitalized G&A which has been allocated between oil and natural gas operations and acquisitions, and exclude purchases of equipment still held in inventory and administrative capital expenditures.

(2) Reserve additions exclude revisions.

(3) Reserve additions include revisions.

(4) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

Finding, development and acquisition ("FD&A") costs are broken down according to oil and natural gas operations, acquisitions and dispositions, and total activities. Oil and natural gas operations include all capital activities in which the Company participated, including operations on the acquired properties after their respective closing dates, but exclude reserve revisions. FD&A costs on the acquired properties are based on the reserve evaluation as at each respective year end less new reserves from operations post closing and were increased by the amount of production from the closing date to December 31 of the respective year to provide an estimate of the reserves purchased. FD&A costs on the disposed properties are based on the reserve evaluation as at December 31, of the year prior to the closing date and were decreased by the amount of production to the closing date. FD&A costs for total activities include operations, acquisitions, dispositions and reserve revisions.

Finding and development costs on operations increased in 2008 compared to 2007 and 2006 as Rock spent more capital in the higher cost West Central core area versus the relatively less expensive Plains core area and increased land expenditures over prior years. Capital spending in the West Central core area includes \$14 million for infrastructure spending at Saxon and Musreau/Kakwa. Reserve bookings increased at Saxon based on well performance; however, Musreau/Kakwa wells have not performed as well as expected. New reserve bookings at Elmworth have been lower than expected but there is little production history with these wells and we do expect some upward revisions in the future. FD&A costs for the West Central core area have been higher than expected in part due to the high infrastructure component and lower initial reserve bookings at Elmworth based on early results. In the Plains core area remediation efforts to solve the gas migration issue at our Edam heavy oil property were slowed by the industry approval process. As a result only one of the three affected wells was on production for a significant amount of time in 2008. A second well was placed on production late in 2008 and a third well should be on production in mid 2009. Production from the first remediated well has been more encouraging lately and Management still believes more reserves will ultimately be recoverable at Edam. In addition Rock started to experience higher water cuts in some wells at our Upgrader heavy oil property and a negative reserve revision has been booked as a result. Longer term well performance will be required to determine ultimate recovery. Of the heavy oil wells drilled in 2008, 15 (15.0 net) have reserves assigned as expected, however 3 (3.0 net) wells experienced production issues within months after completion have no reserves assigned to them. FD&A costs for the Plains core area are generally in line with our expectations. Overall, FD&A costs for 2008 are high. On a three year basis the FD&A costs are more reflective of the progress made in growing the Company and generate recycle ratios (FD&A divided by operating netback) of 1.8:1 for operations and 1.6:1 overall.

LAND HOLDINGS

The following table summarizes Rock's land holdings as at December 31, 2008 and 2007:

(acres)		Dec. 31, 2008	Dec. 31, 2007	Change
Developed	– Gross	81,091	87,882	(8)%
	– Net	30,739	32,406	(5)%
Undeveloped	– Gross	135,573	135,069	0%
	– Net	80,574	61,718	31%
Total	– Gross	216,664	222,951	(3)%
	– Net	111,313	94,123	18%

NET ASSET VALUE

The following table summarizes Rock's net asset value and net asset value per share as at December 31, 2008 and December 31, 2007:

(\$000 except number of shares and net asset value per share)	Dec. 31, 2008	Dec. 31, 2007	Change
Proved plus probable reserves ⁽¹⁾ ⁽²⁾	177,466	152,420	20%
Undeveloped land ⁽³⁾	15,425	13,380	15%
Working capital including debt	(38,622)	(29,094)	33%
Net asset value	154,269	136,706	16%
Year-end shares outstanding (000)	25,900	25,878	0%
Net asset value per share	\$ 5.96	\$ 5.28	16%
Option proceeds	5,390	7,893	(32)%
Net asset value	159,659	144,599	14%
Fully diluted shares outstanding (000)	27,644	28,185	(2)%
Net asset value per share (fully diluted)	\$ 5.78	\$ 5.13	16%

- (1) Proved plus probable reserves value is based on the net present value of future net revenue from gross reserves using GLJ Petroleum Consultants Ltd.'s January 2008 and 2007 forecast pricing and costs estimates and using a discount rate at 10 percent. Net present value of future net revenue does not represent fair market value.
- (2) Reserve values are based on the new Alberta royalty regime for year-end 2008 and the existing Alberta royalty regime for year-end 2007. Note the range of reserve values for 2007 under a high and low royalty assumption case for the new Alberta royalty regime was \$144,747 to \$152,420 as disclosed in the 2007 Annual Report.
- (3) Undeveloped land value is based on the actual cost of land purchased at land sales; land acquired from ELM/Optimum/Qwest in the second quarter of 2005 has been valued at \$100 per acre and land acquired through the Greenbank acquisition in the third quarter of 2007 has been valued at \$200 per acre.

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 office premises.

Obligations with a fixed term are as follows:

	2009	2010	2011	2012	2013
Office premise leases	\$ 828	\$ 828	\$ 828	\$ 552	\$ nil
Processing agreements	360	288	238	159	nil
Demand bank loan ⁽¹⁾	\$ 34,175	\$ -	\$ -	\$ -	\$ -

- (1) The demand bank loan is currently under its annual review and is expected to remain in place.

OUTSTANDING SHARE DATA

At December 31, 2008 and to date, Rock had 25,889,843 common shares outstanding. At December 31, 2008 the Company had 1,744,204 stock options outstanding with an average exercise price of \$3.09 per share. As of the date hereof Rock has 1,688,871 options outstanding.

OFF-BALANCE-SHEET ARRANGEMENTS

Rock does not have any special-purpose entities nor is it party to any arrangement that would be excluded from the balance sheet.

RELATED-PARTY TRANSACTIONS

The Company has not entered into any related-party transactions during the reporting period.

DISCLOSURE CONTROLS AND PROCEDURES

The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's disclosure controls and procedures at the financial year-end of the Company and have concluded that the Company's disclosure controls and procedures are effective at the financial year-end of the Company for the foregoing purposes. All control systems by their nature have inherent limitations and, therefore, Rock's disclosure controls and procedures are believed to provide reasonable, but not absolute, assurance that:

- the communications by the Company with the public are timely, factual and accurate and broadly disseminated in accordance with all applicable legal and regulatory requirements;
- non-publicly disclosed information remains confidential; and
- trading of the Company's securities by directors, officers and employees remains in compliance with applicable securities laws.

INTERNAL CONTROL OVER FINANCIAL REPORTING

The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal control over financial reporting to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with the Canadian GAAP. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal control over financial reporting at the financial year end of the Company and concluded that the Company's internal control over financial reporting is effective, at the financial year end of the Company, for the foregoing purpose.

The Company is required to disclose herein any change in the Company's internal control over financial reporting that occurred during the period beginning on October 1, 2008 and ended on December 31, 2008 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting. No material changes in the Company's internal control over financial reporting were identified during such period that has materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

It should be noted a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

CHANGE IN ACCOUNTING POLICIES

As of January 1, 2008 the Company adopted new policies to implement the pronouncements from the Canadian Institute of Chartered Accountants ("CICA") in respect of capital disclosures and financial instruments – presentation and disclosures. The new standard for capital disclosures requires disclosure on objectives, policies and processes for managing capital. The new standard for financial instruments places increased emphasis and disclosure on the nature and extent of risks arising from financial instruments and how they are managed. The application of these policies did not result in changes to amounts reported in the consolidated financial statements for the period ended December 31, 2008.

NEW ACCOUNTING PRONOUNCEMENTS

GOODWILL AND INTANGIBLE ASSETS

The CICA in February 2008 issued CICA Handbook section 3064, Goodwill and Intangible Assets, and amended section 1000, Financial Statement Concepts, clarifying the criteria for recognition of assets, intangible assets and internally developed intangible assets. Items that no longer meet the definition of an asset are no longer recognized with assets.

Rock will adopt this section effective January 1, 2009.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In February 2008 the CICA confirmed the implementation of International Financial Reporting Standards (“IFRS”) as part of Canadian GAAP. The adoption of IFRS in Canada will result in significant changes to current Canadian GAAP and to financial reporting practices followed by Rock. IFRS accounting standards are to be implemented for years beginning after December 31, 2010. Rock will be required to adopt the standard for the year beginning January 1, 2011.

Rock has participated in an industry task force which has identified issues, helped understand the new accounting policies and the choices that can be made and provided guidance regarding the adoption of IFRS for the oil and natural gas industry. In order to transition to IFRS the Company will have to adopt new accounting policies, procedures and reporting standards. As part of this process Rock will have to transition from the full cost method of accounting, which the Company currently follows, to a method acceptable under IFRS. At a minimum IFRS will require the Company to identify new units of account and cash generating units at a more finite level than under full cost accounting and will also require asset impairment testing at the new unit levels. Setting new IFRS accounting policies and the identification of cash generating units will begin in the second quarter of 2009 but not likely completed until the fourth quarter of 2009. It is likely Rock will need to put in place a new accounting system in order to more effectively handle IFRS accounting procedures. Rock will begin to investigate new systems in the second quarter of 2009 with the intent of having a new system in place and operating by January 2010. Currently IFRS is proposing an amendment that, if successful, would allow Canadian companies using the full cost method of accounting for exploration and development activities to utilize their independent reserve report to allocate certain property, plant and equipment costs to newly defined units of account at the time of transition to IFRS. The proposed amendment would significantly reduce the amount of work required to transition the Company to IFRS. The Company intends to have an opening balance sheet that is IFRS compliant for January 1, 2010 at which point both IFRS and Canadian GAAP compliant financial statements will be maintained in order to facilitate full IFRS compliant reporting effective January 1, 2011. Rock will have in-house staff attend training courses specific to IFRS adoption and policies. Rock may engage external consultants to help with the transition and adoption of IFRS.

BUSINESS COMBINATIONS

In January 2009, the CICA issued new standards for Business Combinations. This standard is effective January 1, 2011 and applies prospectively to business combinations for which the acquisition date is on or after the first annual reporting period beginning on or after January 1, 2011 for the Company. Early adoption is permitted. This standard replaces Business Combination and harmonizes the Canadian standards with IFRS. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting this standard is expected to have a significant impact on the way the Company accounts for future business combinations.

CRITICAL ACCOUNTING ESTIMATES

A summary of the Company's significant accounting policies is contained in note 2 to the audited consolidated financial statements. 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.

Oil and Natural Gas Accounting – Reserves Recognition – Rock retained independent petroleum engineering consultants GLJ Petroleum Consultants Ltd. (GLJ) to evaluate its oil and natural gas reserves, prepare an evaluation report, and report to the Company's Reserves Committee. The process of estimating 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 oil and natural gas prices and costs change. Reserves can be classified as proved, probable or possible with decreasing levels of certainty to the likelihood that the reserves will be ultimately produced.

Oil and Natural Gas Accounting – Full Cost Accounting – Under the full cost method of accounting for exploration and development activities, all costs associated with these activities are capitalized. The aggregate net capitalized costs and estimated future abandonment costs, less estimated salvage values, are amortized using the unit-of-production method based on estimated proved oil and natural gas reserves, resulting in a depletion expense. The depletion expense is most affected by the estimate of proved reserves and the cost of unproved properties. Unproved costs are reviewed quarterly to determine if proved reserves have been established, at which point the associated costs are included in the depletion calculation. Changes to any of these estimates may affect Rock's earnings.

Under the full cost method of accounting, the Company's investment in oil and natural gas assets is evaluated at least annually to consider whether the investment is recoverable and the carrying amount does not exceed the value of the properties, a process known as the "ceiling test". The carrying value of oil and natural gas properties and production equipment is compared to the sum of undiscounted cash flows expected to result from Rock's proved reserves. If the carrying value is not fully recoverable, the amount of impairment is measured by comparing the carrying value of property and equipment to the estimated net present value of future cash flows from proved plus probable reserves using a risk-free interest rate. Any excess carrying value above the net present value of the future cash flows is recorded as a permanent impairment. Reserve, revenue, royalty and operating cost estimates and the timing of future cash flows are all critical components of the ceiling test. Revisions of these estimates could result in a write-down of the carrying amount of oil and natural gas properties.

Asset Retirement Obligations – The Company recognizes the estimated fair value of an asset retirement obligation (ARO) in the period in which it is incurred as a liability, 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 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. Actual costs incurred on settlement of the ARO are charged against the ARO. 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.

Stock-Based Compensation – 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 stock-based compensation expense and contributed surplus over the vesting period of the option. Stock-based compensation expense 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 stock-based compensation expense.

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 exploration and production 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 U.S./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 in 2009, 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 further 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, or all, 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.

Rock is subject to various regulatory risks, principally environmental in nature. 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. Increased public and political concern regarding climate change issues will likely result in increased regulation regarding emissions standards. Given that the Company produces hydrocarbons, such regulation could cause Rock to alter the way it operates and also result in additional costs and taxes associated with climate change regulation which could have a material effect on the Company.

ENVIRONMENTAL RISK AND REGULATION

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. 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. In 2002, the Government of Canada ratified the Kyoto Protocol (the "Protocol"), which calls for Canada to reduce its greenhouse gas emissions to 6 percent below 1990 emission levels. The federal government has introduced legislation aimed at reducing greenhouse gas emissions using an "intensity based" approach, the specifics of which have yet to be determined. Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by the House of Commons on February 14, 2007. There has been much public debate with respect to Canada's ability to meet these targets and the federal government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Protocol or as otherwise determined could have a material impact on the nature of oil and natural gas operations, including those of the Company.

In Alberta, the reduction emission guidelines outlined the Climate Change and Emissions Management Amendment Act (the "Act") came into effect July 1, 2007. Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12 percent. Industries have three options to choose from in order to meet the reduction requirements outlined in the Act, and these are: (a) by making improvement to operations that result in reductions; (b) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emissions; or (c) by contributing to the Climate Change and Emissions Management Fund. Pursuant to the Act, March 31, 2008 was the deadline for industries to choose one of these options or a combination thereof. On April 26, 2007, the federal government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan"), also known as ecoACTION which includes the Regulatory Framework for Air Emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products.

On January 24, 2008, the Alberta government announced its plan to reduce projected emissions in the province by 50 percent by 2050. This will result in real reductions of 14 percent below 2005 levels. The Alberta government stated it would form a government-industry council to determine a go-forward plan for implementing technologies, which will significantly reduce greenhouse gas emissions by capturing air emissions from industrial sources and locking them permanently underground in deep rock formations (carbon capture). In addition, the plan calls for energy conservation by individuals and for increased investment in clean energy technologies and incentives for expanding the use of renewable and alternative energy sources such as bioenergy, wind, solar, hydrogen, and geothermal. Initiatives under this theme will account for 18 percent of Alberta's reductions.

On January 31, 2008, the Government of Canada and the Province of Alberta released the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

On March 10, 2008, the Government of Canada released “Turning the Corner – Taking Action to Fight Climate Change” which provides some additional guidance with respect to the Government of Canada’s plan to reduce greenhouse gas emissions by 20 percent by 2020 and by 60 percent to 70 percent by 2050. The updated action plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and natural gas, and refining industries. The updated action plan is intended to force industry to reduce greenhouse gas emissions and to create a carbon emissions trading market, including an offset system, to provide incentive to reduce greenhouse gas emission and establish a market price for carbon. The updated action plan provides for: (i) mandatory reductions of 18 percent from the 2006 baseline starting in 2010 and by an addition 2 percent in subsequent years for existing facilities; (ii) new facilities built between 2004 and 2011 will have mandatory emissions standards based upon clean fuel standards (gas) with a 2 percent reduction below the third year’s intensity levels; and (iii) oil sands plants built in 2012 and later which use heavier hydrocarbons and upgraders and in situ production will have mandatory standards in 2018 based on carbon capture and storage or other green technologies intensity. For the upstream oil and natural gas industry, the updated action plan also provides for a company threshold of 10,000 boe per day and facility threshold of 3,000 tonnes of CO₂.

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.

ADDITIONAL INFORMATION

Further information regarding the Company, including the Company’s Annual Information Form, can be accessed under the Company’s public filings found on SEDAR at www.sedar.com. Information can also be obtained by contacting Rock Energy Inc., Suite 800, 607 – 8th Avenue S.W., Calgary, Alberta, T2P 0A7.

Management's Report

TO THE SHAREHOLDERS OF ROCK ENERGY INC.:

The consolidated financial statements of Rock Energy Inc. were prepared by management in accordance with appropriately selected generally accepted accounting principles in Canada. Management has used estimates and careful judgement, particularly in those circumstances where transactions affecting current periods are dependent on information not known until a future period. The financial and operational information contained in this annual report is consistent with that reported in the financial statements.

Management is responsible for the integrity of the financial and operational information contained in this report. The Company has designed and maintains internal controls to provide reasonable assurance that assets are properly safeguarded and that the financial records are well maintained and provide relevant, timely and reliable information to management. The consolidated financial statements have been prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized in the notes to the consolidated financial statements.

External auditors appointed by the shareholders have conducted an independent examination of the corporate and accounting records in order to express their opinion on the consolidated financial statements. The Audit Committee has met with the external auditors and management in order to determine if management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit Committee.

(signed) "Allen J. Bey"

(signed) "Peter D. Scott"

Allen J. Bey

President and Chief Executive Officer

Peter D. Scott

Vice President, Finance and Chief Financial Officer

March 12, 2009

Auditors' Report to the Shareholders

We have audited the consolidated balance sheets of Rock Energy Inc. as at December 31, 2008 and 2007 and the consolidated statements of income, comprehensive income and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2008 and 2007 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

(signed)

KPMG LLP

Chartered Accountants

Calgary, Canada

March 12, 2009

Consolidated Balance Sheets

(000s of dollars) As at	December 31, 2008	December 31, 2007
Assets		
Current assets		
Accounts receivable	\$ 11,896	\$ 8,473
Prepaid expenses	908	1,383
	12,804	9,856
Property, plant and equipment (note 6)	137,706	114,891
Goodwill (note 6)	–	5,748
	\$ 150,510	\$ 130,495
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	\$ 17,251	\$ 11,523
Bank debt (note 8)	34,175	27,405
	51,426	38,928
Future tax liability (note 12)	5,565	1,533
Asset retirement obligation (note 9)	4,497	3,840
Shareholders' equity		
Share capital (note 10)	81,600	81,600
Contributed surplus (note 11)	3,458	2,521
Retained earnings	3,964	2,073
	89,022	86,194
Commitments (note 13)		
	\$ 150,510	\$ 130,495

See accompanying notes to consolidated financial statements.

Approved by the Board:

(signed) "James K. Wilson"

James K. Wilson

Director

(signed) "Allen J. Bey"

Allen J. Bey

Director

Consolidated Statements of Income, Comprehensive Income and Retained Earnings

(000s of dollars, except per share amounts) Years ended	December 31, 2008	December 31, 2007
Revenues:		
Oil and natural gas	\$ 80,138	\$ 36,042
Royalties	(17,094)	(7,035)
Other income	138	79
	63,182	29,086
Expenses:		
General and administrative	3,236	2,739
Operating	17,361	9,925
Interest	1,565	1,157
Stock-based compensation (note 11)	1,158	931
Goodwill impairment (note 6)	5,748	–
Depletion, depreciation, and accretion	28,109	14,143
	57,177	28,895
Income before taxes	6,005	191
Taxes		
Provincial capital taxes (note 12)	179	76
Future income taxes (reduction) (note 12)	3,935	(446)
Net income and comprehensive income for the year	1,891	561
Retained earnings, beginning of year	2,073	1,512
Retained earnings, end of year	\$ 3,964	\$ 2,073
Diluted and basic net income per share (note 10)	\$ 0.07	\$ 0.03

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

(000s of dollars) Years ended	December 31, 2008	December 31, 2007
Cash provided by (used in):		
Operating:		
Net income for the year	\$ 1,891	\$ 561
Asset retirement expenditures	(94)	–
Add: Non-cash items:		
Depletion, depreciation, and accretion	28,109	14,143
Goodwill impairment	5,748	–
Stock-based compensation	1,158	931
Future income taxes (reduction)	3,935	(446)
	40,747	15,189
Changes in non-cash working capital	843	(1,035)
	41,590	14,154
Financing:		
Issuance of common shares	81	12,456
Bank debt	6,770	10,903
Repurchase of stock options	(205)	(51)
	6,646	23,308
Investing:		
Property, plant and equipment	(51,414)	(25,575)
Acquisition of property, plant and equipment (note 5)	–	(12,644)
Disposition of property, plant and equipment	1,243	–
Changes in non-cash working capital	1,935	757
	(48,236)	(37,462)
Change in cash	–	–
Cash beginning of year	–	–
Cash end of year	\$ –	\$ –
Interest and taxes paid and received:		
Interest paid	\$ 1,565	\$ 1,190
Interest received	–	34
Taxes paid	92	142

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements

Years ended December 31, 2008 and 2007

1. NATURE OF OPERATIONS

Rock Energy Inc. (the "Company" or "Rock") is actively engaged in the exploration, production and development of oil and natural gas in Western Canada.

2. SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of Rock are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles (GAAP).

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates.

(A) CONSOLIDATION

These consolidated financial statements include the accounts of Rock Energy Inc., and its wholly owned subsidiaries Rock Energy Ltd. and Rock Energy Production Partnership. All inter-company transactions and balances have been eliminated upon consolidation.

(B) CASH

Cash and cash equivalents are comprised of cash and short-term investments with an original maturity date of three months or less.

(C) JOINT OPERATIONS

A substantial portion of the Company's oil and natural gas exploration and development activities is conducted jointly with others and, accordingly, these consolidated financial statements reflect only the Company's proportionate interest in such activities.

(D) PROPERTY, PLANT AND EQUIPMENT

Capitalized costs: The Company follows the full cost method of accounting for its oil and natural gas operations, whereby all costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges directly related to exploration and development activities. Proceeds from the sale of oil and natural gas properties are applied against capital costs, with no gain or loss recognized, unless such a sale would change the rate of depletion and depreciation by 20 percent or more, in which case a gain or loss would be recorded.

Depletion, depreciation and amortization: The capitalized costs are depleted and depreciated using the unit-of-production method based on proved petroleum and natural gas reserves before royalties, as determined by independent consulting engineers. Oil and natural gas liquids reserves and production are converted into equivalent units of natural gas based on relative energy content. Office furniture and equipment are recorded at cost and depreciated on a declining balance basis using a rate of 20 percent. The cost of acquiring and evaluating unproved properties is initially excluded from the depletion calculation. These properties are assessed periodically for impairment. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to the costs subject to depletion.

Ceiling test: Rock calculates its ceiling test by comparing the carrying amount of oil and natural gas properties and production equipment to the sum of undiscounted cash flows from proved reserves. If the carrying amount is not fully recoverable, the amount of impairment is measured by comparing the carrying amount of property and equipment to the estimated net present value of future cash flows from proved plus probable reserves, using a risk-free interest rate and expected future prices, and the lower of cost, less impairment, and market value of unproved properties. Any excess carrying amount above the net present value of the future cash flows is recorded as a permanent impairment.

Asset retirement obligations: The Company records the fair value of an asset retirement obligation (ARO) as a liability in the period in which it incurs a legal obligation to restore an oil and natural gas property, typically when a well is drilled or other equipment is put in place. The associated asset retirement costs are capitalized as part of the carrying amount of the related asset and depleted on a unit-of-production method over the life of the proved reserves. Subsequent to initial measurement of the obligations, the obligations are adjusted at the end of each reporting period to reflect the passage of time and changes in estimated future cash flows underlying the obligation. Actual costs incurred on settlement of the ARO are charged against the ARO to the extent incurred, with any remainder recorded to earnings as a gain or loss.

(E) INCOME TAXES

Income taxes are calculated using the asset and liability method of tax accounting. Temporary differences arising from the difference between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax assets and liabilities. Future income tax assets and liabilities are calculated using tax rates anticipated to apply in the periods when the temporary differences are expected to reverse. A valuation allowance is recorded against any future income tax assets if it is more likely than not that the asset will not be realized.

(F) FLOW-THROUGH SHARES

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. Future tax liabilities and share capital are adjusted by the estimated cost of the renounced tax deduction when the expenses are renounced.

(G) STOCK-BASED COMPENSATION

The Company grants options to purchase common shares to employees and directors under its stock option plan. Awards are accounted for using the fair value of accounting for stock-based compensation. Under the fair value method, an estimate of the value of the option is determined at the time of grant using the Black-Scholes option pricing model. The fair value of the option is recognized as an expense and contributed surplus over the vested life of the option. Upon the exercise of stock options the consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

(H) REVENUE RECOGNITION

Revenue from the sale of oil and natural gas is recognized based on volumes delivered to customers at contractual delivery points and rates.

(I) MEASUREMENT UNCERTAINTY

The amounts recorded for depletion and depreciation of property, plant and equipment, the provision for asset retirement obligations, the amounts used for ceiling test calculations and fair value of identifiable assets for goodwill impairment are based on estimates of reserves and future costs. The Company's reserve estimates are reviewed annually by an independent engineering firm. The amounts disclosed relating to fair values of stock options issued are based on estimates of future volatility of the Company's share price, expected lives of options, and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements of changes in such estimates in future periods could be material.

(J) PER SHARE AMOUNTS

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year. Diluted per share amounts are calculated based on the treasury stock method whereby the weighted average number of shares is adjusted for the dilutive effect of options. The treasury stock method assumes that any proceeds received upon the exercise of stock options would be used to purchase common shares at the estimated average market price of the common shares during the period. Anti-dilutive instruments are not included in the calculation.

3. ACCOUNTING POLICIES CHANGES

(A) FINANCIAL INSTRUMENTS

On January 1, 2008 the Company adopted the new standards relating to "Financial Instruments – Disclosures" and "Financial Instruments – Presentation", which replaced the previous standard "Financial Instruments – Disclosure and Presentation". The new disclosure standard outlines the disclosure requirements for financial instruments and non-financial derivatives. The guidance prescribes an increased importance on risk disclosures associated with recognized and unrecognized financial instruments and how such risks are managed. Specifically, it requires disclosure of the significance of financial instruments for a company's financial position. In addition, the guidance outlines revised requirements for the disclosure of qualitative and quantitative information regarding exposure to risks arising from financial instruments. The new presentation standard requirements are relatively unchanged from the previous presentation requirements.

(B) CAPITAL DISCLOSURES

On January 1, 2008 the Company adopted the new standards for Capital Disclosures requiring disclosures regarding the Company's objectives, policies and processes for managing capital. These disclosures include a description of what the Company manages as capital, the nature of externally imposed capital requirements, how the requirements are incorporated into the Company's management of capital, whether the requirements have been complied with, or consequences of non-compliance and an explanation of how the Company is meeting its objectives for managing capital. In addition, quantitative data about capital and whether the Company has complied with all capital requirements are also required (see note 12).

4. PENDING ACCOUNTING CHANGES

(A) GOODWILL

As of January 1, 2009 the Company will be required to adopt new standards for Goodwill and Intangible Assets, which defines the criteria for the recognition of intangible assets. Items that no longer meet the definition of an asset are no longer recognized with assets. The Company does not expect the adoption of this standard will have any impact on the financial statements.

(B) INTERNATIONAL REPORTING STANDARDS

In 2008, the CICA Accounting Standards Board confirmed the changeover to IFRS from Canadian GAAP will be required for publicly accountable enterprises effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. The eventual changeover to IFRS represents changes due to new accounting standards. The Company continues to monitor and assess the impact of the convergence of Canadian GAAP and IFRS but has not at this time made any determination on the impact on the Company's financial statements.

(C) BUSINESS COMBINATIONS

In January 2009, the CICA issued new standards for Business Combinations. This standard is effective January 1, 2011 and applies prospectively to business combinations for which the acquisition date is on or after the first annual reporting period beginning on or after January 1, 2011 for the Company. Early adoption is permitted. This standard replaces Business Combination and harmonizes the Canadian standards with IFRS. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting this standard is expected to have a significant impact on the way the Company accounts for future business combinations.

5. ACQUISITION OF GREENBANK ENERGY LTD.

On September 28, 2007 the Company purchased a private company by way of a plan of arrangement for cash and shares of the Company. The acquisition has been accounted for using the purchase method and the results of operations for the transaction are included in the financial statements beginning in the fourth quarter of 2007.

The purchase price equation is as follows:

(\$000)	
Property, plant and equipment	\$ 28,127
Bank debt	(5,537)
Working capital deficiency	(330)
Asset retirement obligation	(761)
Future income tax asset	2,963
	<hr/>
	\$ 24,462
Consideration provided:	
Cash from private placement	\$ 12,144
Common shares (3,143,167 issued)	11,818
Transaction costs	500
	<hr/>
	\$ 24,462

6. PROPERTY, PLANT AND EQUIPMENT

(\$000)	December 31, 2008	December 31, 2007
Petroleum and natural gas properties	\$ 200,994	\$ 150,408
Other assets	1,432	1,354
	202,426	151,762
Accumulated depletion and depreciation	(64,720)	(36,871)
	\$ 137,706	\$ 114,891

At December 31, 2008, the depletable base for the petroleum and natural gas properties included \$11,704 (December 31, 2007 – \$14,404) of future capital costs and excluded \$15,425 (December 31, 2007 – \$13,380) of unproved property costs.

During the year ended December 31, 2008, \$1,592 (year ended December 31, 2007 – \$2,004) of administrative costs relating to exploration and development activities were capitalized as part of property, plant and equipment.

At December 31, 2008, the Company applied the ceiling test calculation to its petroleum and natural gas properties using expected future market prices. These expected future market prices were forecast by the Company's independent reserve evaluators and then adjusted for commodity price differentials specific to the Company's production. The following table exhibits the benchmark prices used in the ceiling test:

	Oil WTI (Cushing, Oklahoma) (US\$/bbl)	Oil Edmonton Par (40° API) (CDN\$/bbl)	Natural Gas AECO-C Spot Price (CDN\$/mmbtu)	Heavy Oil at Hardisty (12° API) (CDN\$/bbl)	Currency Exchange Rate (US\$/CDN\$)
2009	57.50	68.61	7.58	43.10	0.825
2010	68.00	78.94	7.94	49.76	0.850
2011	74.00	83.54	8.34	54.35	0.875
2012	85.00	90.92	8.70	59.23	0.925
2013	92.01	95.91	8.95	62.54	0.950
2014	93.85	97.84	9.14	63.82	0.950
2015	95.73	99.82	9.34	65.13	0.950
2016	97.64	101.83	9.54	66.46	0.950
2017	99.59	103.89	9.75	67.83	0.950
2018	101.59	105.99	9.95	69.22	0.950
Thereafter (escalation)	2.0%/yr	2.0%/yr	2.0%/yr	2.0%/yr	0.950

Goodwill of \$5,748 was written off due to the application of a market based impairment test as at September 30, 2008. The Company does not have any impairment related to its property, plant and equipment.

7. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

COMMODITY PRICE RISK

Due to the volatile nature of commodity prices the Company is potentially exposed to adverse consequences if commodity prices decline. However, if commodity prices are hedged potential upside gains may also be forfeited. As of December 31, 2008 the Company did not have any commodity price contracts. A \$1.00 per barrel change in the price the Company would have received for its oil and natural gas liquids production is estimated to result in a \$352 change in net income for 2008. A \$0.25 per mcf change in the price the Company would have received for its natural gas production is estimated to result in a \$500 change in net income for 2008.

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 of December 31, 2008 the Company did not have any foreign currency exchange contracts in place. A \$0.01 change in the Canadian dollar/U.S. dollar exchange rate is estimated to result in a \$535 change in net income for 2008.

CREDIT RISK

Substantially all of the 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 and joint interest partners are generally collected within one to three months. The Company attempts to mitigate this risk by entering into transactions with long-standing and reputable organizations and by obtaining partner approval of significant capital expenditures and payment of cash advances wherever possible. Further risk exists with joint interest partners as disagreements occasionally arise and may increase the potential for non-collection. 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 who 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 December 31, 2008 the Company's receivables consisted of \$7,966 (December 31, 2007 – \$4,132) from joint interest partners, \$3,397 (December 31, 2007 – \$3,228) from oil and gas marketers, and \$533 (December 31, 2007 – \$1,113) of other trade receivables.

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.

INTEREST RATE RISK

The Company is exposed to interest rate risk to the extent that bank debt is at a floating or short term rate of interest. The Company does not have any financial or interest rate contracts in place as of December 31, 2008. A 1 percent change to the floating or short term interest rates is estimated to result in a \$218 change in net income for 2008.

8. BANK DEBT

At December 31, 2008 the Company had a demand operating facility with a Canadian chartered bank subject to the bank's valuation of the Company's oil and natural gas properties. The limit under the facility at December 31, 2008 was \$51 million. 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 prevailing bankers' 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 next review is to be completed before April 30, 2009.

9. ASSET RETIREMENT OBLIGATION

The Company's asset retirement obligations result 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 asset retirement obligations at December 31, 2008 was approximately \$7,716 (December 31, 2007 – \$6,474), which will be incurred between 2009 and 2020. A credit-adjusted risk-free rate of 8 percent and an annual inflation rate of 1.5 percent were used to calculate the future asset retirement obligation.

	December 31, 2008	December 31, 2007
Balance, beginning of year	\$ 3,840	\$ 2,094
Liabilities incurred/acquired	549	1,592
Dispositions	(58)	–
Accretion	260	154
Actual retirement costs	(94)	–
Balance, end of year	\$ 4,497	\$ 3,840

10. SHARE CAPITAL

(A) AUTHORIZED:

Unlimited number of voting common shares, without stated par value.

300,000 preference shares, without stated par value.

(B) COMMON SHARES ISSUED

Common Shares of Rock	Number	Amount (\$000)
Issued and outstanding as at December 31, 2006	19,637,321	\$ 57,326
Issued for flow-through shares (i)	10,007	42
Issued in private placement	2,998,623	12,144
Issued for property acquisitions	3,143,167	11,818
Issued for flow-through shares (ii)	88,524	270
Issued and outstanding as at December 31, 2007	25,877,642	\$ 81,600
Future tax effect of flow-through share renouncements (ii)	–	(98)
Issued on exercise of stock options	13,334	59
Issued for flow-through shares (i)	8,867	39
Issued and outstanding as at December 31, 2008	25,899,843	\$ 81,600

- (i) In accordance with the Company's stock option plan, some options were exercised in exchange for flow-through shares of the Company.
- (ii) The Company issued flow-through shares to new management appointees. By February 29, 2008 all of the renouncements were made.

(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 majority of options vest yearly in one-third tranches beginning on the first anniversary of the grant date and expire one year after vesting. Options expiring are usually replaced with another grant that vests in two years and expires in three years. At the Company's discretion the options can be exercised for cash. The following table summarizes the status of the Company's stock option plan as at December 31, 2007 and December 31, 2006 and changes during the year ended on those dates:

	December 31, 2008		December 31, 2007	
	Options	Weighted Average Exercise Price (\$)	Options	Weighted Average Exercise Price (\$)
Outstanding, beginning of year	2,307,822	\$ 3.42	1,767,277	\$ 4.19
Granted	444,532	\$ 2.92	1,258,366	\$ 2.79
Exercised	(198,240)⁽ⁱ⁾	\$ 3.26	(82,485) ⁽ⁱ⁾	\$ 3.49
Forfeited	(423,328)	\$ 3.28	(286,890)	\$ 4.23
Expired	(386,582)	\$ 4.61	(348,446)	\$ 4.36
Outstanding, end of year	1,744,204	\$ 3.09	2,307,822	\$ 3.42

- (i) Options were put back to the Company for in-the-money gain.
- (ii) 184,906 options were put back to the Company for in-the-money gain.

Options outstanding and exercisable under the stock option plan are summarized below as at December 31, 2008:

	Outstanding Options			Exercisable Options	
	Number of Options	Weighted Average Exercise Price	Weighted Average Years to Expiry	Number of Options	Weighted Average Exercise Price (\$)
\$1.37 – \$2.04	112,000	\$ 1.62	2.88	–	\$ –
\$2.25 – \$3.32	1,278,207	\$ 2.82	1.85	322,389	\$ 2.72
\$3.41 – \$5.11	353,997	\$ 4.52	1.13	202,331	\$ 4.86
	1,744,204	\$ 3.09	1.79	524,720	\$ 3.54

(D) PER SHARE AMOUNTS

The weighted average number of common shares outstanding during the year ended December 31, 2008 of 25,885,309 (year ended December 31, 2007 – 21,238,886) was used to calculate per share amounts. To calculate diluted common shares outstanding, the treasury method was used. Under this method, in-the-money options are assumed exercised and the proceeds used to repurchase shares at the year-end date of December 31, 2008. As at December 31, 2008 an additional 37,714 (December 31, 2007 – nil) common shares were used to calculate diluted earnings per share.

11. STOCK-BASED COMPENSATION

Options granted to employees and non-employees after March 31, 2003 are accounted for using the fair value method. The fair value of common share options granted for the year ended December 31, 2008 was estimated to be \$616 (year ended December 31, 2007 – \$1,434) as at the grant date using the Black-Scholes option pricing model and the following assumptions:

Risk-free interest rate	4.00% – 5.25%
Expected life	Three-year average
Expected volatility	65% – 85%
Expected dividend yield	0%

Contributed surplus:

	December 31, 2008	December 31, 2007
Balance, beginning of year	\$ 2,521	\$ 1,641
Stock-based compensation expense	1,158	931
Net benefit on options exercised ⁽¹⁾	(221)	(51)
Balance, end of year	\$ 3,458	\$ 2,521

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

12. INCOME TAXES

The provision for income taxes varies from the amount that would be computed by applying the expected tax rate to income before taxes. The expected tax rate used was 29.8 percent (December 31, 2007 – 32.40 percent). The principal reasons for differences between such “expected” income tax expense and the amount actually recorded are as follows:

	December 31, 2008	December 31, 2007
Income before taxes	\$ 6,005	\$ 191
Statutory income tax rate	29.8%	32.4%
Expected income taxes	\$ 1,789	\$ 62
Add (deduct):		
Stock-based compensation	345	302
Change in enacted rates	38	(365)
Other	72	(375)
Goodwill impairment	1,714	–
Change in valuation allowance	(23)	(70)
Future income taxes (reduction)	\$ 3,935	\$ (446)
Capital tax	179	76
Provision for (recovery of) income taxes	\$ 4,114	\$ (370)

Future income tax assets or liabilities recognized on the consolidated balance sheets are comprised of temporary differences. The after-tax effect of these temporary differences is summarized as follows:

	December 31, 2008	December 31, 2007
Loss carry-forwards	\$ 3,485	\$ 4,587
Property, plant and equipment	(60)	(2,070)
Deferral of partnership earnings	(9,810)	(4,808)
Share issuance costs	231	331
Asset retirement obligation	1,214	1,075
Calculated future income tax liability	(4,940)	(885)
Valuation allowance	(625)	(648)
Future income taxes (liability)	\$ (5,565)	\$ (1,533)

At December 31, 2008, Rock and its subsidiaries had tax pools totalling \$148.6 million prior to the allocation of deferred partnership income and \$114.8 million after the allocation of deferred partnership income. The non-capital losses prior to the allocation of deferred partnership income expire as follows:

2014	\$ 1,320
2015	1,031
2026	6,695
2027	1,893
	\$ 10,939

13. COMMITMENTS

Obligations with a fixed term are as follows:

	2009	2010	2011	2012	2013
Lease of office premises	\$ 828	\$ 828	\$ 828	\$ 552	\$ –
Processing arrangements	\$ 360	\$ 288	\$ 238	\$ 159	\$ –

14. CAPITAL DISCLOSURES

In order to continue the Company's future exploration and development program, the Company must maintain a strong capital base. A strong capital base results in increased market confidence, an essential factor in maintaining existing shareholders and in attracting new investors. The Company's commitment is to establish and maintain a strong capital base to enable the Company to access the equity and debt markets when deemed advisable. 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. It then determines increases or decreases to its capital budget.

The Company considers shareholders' equity, bank debt and working capital as components of its capital base. The Company can access or increase capital through the issuance of shares, through bank borrowings, that are based on reserves, and by building cash reserves by reducing its capital expenditure program. The components of the Company's capital base at December 31, 2008 and 2007 is presented below.

	December 31, 2008	December 31, 2007
Shareholders' equity	\$ 89,022	\$ 86,194
Bank debt	34,175	27,405
Working capital deficiency (excluding bank debt)	4,447	1,667

The Company monitors its capital structure based primarily on its debt-to-annualized funds flow ratio. Debt includes bank debt plus or minus working capital. Annualized funds flow is calculated as funds flow from operations before changes in non-cash working capital from the Company's most recent quarter multiplied by four. The Company's strategy is to maintain this ratio at less than 1.5:1. This ratio may increase on a cyclical basis depending on the timing and nature of the Company's activities and commodity price fluctuations. 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 material changes thereto.

At December 31, 2008, the Company's debt to funds flow ratio was 1.75:1 compared to 0.6:1 at the end of the second and third quarters and 1.3:1 at the end of the first quarter of 2008. The ratio is generally higher at the end of the first and third quarters which tend to be high capital expenditure quarters (the first quarter due to winter access only operations and the third quarter due to post spring break-up activities). The second quarter is typically a low capital expenditure quarter due to spring break-up curtailing operations. The increased activity levels usually result in the Company carrying a higher debt load at the end of the first and third quarters, depending on actual commodity prices. The production additions from activities usually occur in the quarter following the operation and are expected to contribute to increased funds flow, subject to prevailing commodity prices. The ratio has increased at the end of the fourth quarter and is above the Company's target primarily due to a significant decline in commodity prices. Based on the Company's current projections the Company plans on paying down debt but this ratio is expected to be above the target level for all of 2009 but is not expected to breach any debt covenants.

The Company's share capital is not subject to external restrictions but the Company does have financial covenants in regards to its operating bank facility. The facility requires that the Company maintain a working capital ratio of not less than 1:1. The calculation allows for the unused portion of the credit facility to be added to current assets and deduction of the current portion of bank debt from the current liabilities. The Company would be considered in breach of its agreement if the working capital ratio was not maintained, unless consented to by the lender, in which case the bank may demand repayment of the loan.

Historical Five-Year Review

FINANCIAL	2008	2007	2006	2005	2004 ⁽²⁾
Funds from operations ⁽¹⁾ (000)	\$ 40,747	\$ 15,189	\$ 13,867	\$ 11,433	\$ 1,218
Per boe (6:1)	\$ 32.40	\$ 18.93	\$ 18.11	\$ 27.92	\$ 18.39
Per share	\$ 1.57	\$ 0.72	\$ 0.71	\$ 0.74	\$ 0.14
Net income (000)	\$ 1,891	\$ 561	\$ (884)	\$ 1,510	\$ 571
Per boe (6:1)	\$ 1.50	\$ 0.70	\$ (1.15)	\$ 3.69	\$ 8.62
Per share	\$ 0.07	\$ 0.03	\$ (0.05)	\$ 0.10	\$ 0.06
G & A expense per boe (6:1)	\$ 2.57	\$ 3.41	\$ 2.97	\$ 3.44	\$ 14.48
Operating expense (\$/boe)	\$ 13.81	\$ 12.37	\$ 12.08	\$ 11.59	\$ 7.96
Royalty expense (\$/boe)	\$ 13.59	\$ 8.77	\$ 8.98	\$ 12.28	\$ 9.89
Royalty percentage	21.3%	19.5%	20.8%	22.0%	23.0%
Field netback (\$/boe)	\$ 36.33	\$ 23.79	\$ 22.21	\$ 31.98	\$ 25.16
Capital expenditures ⁽²⁾ (000)	\$ 51,415	\$ 25,575	\$ 32,878	\$ 23,644	\$ 6,252
OPERATIONS	2008	2007	2006	2005	2004 ⁽²⁾
Production					
Heavy oil (bbl/d)	1,329	1,194	792	187	0
Light and medium oil (bbl/d)	193	215	179	133	77
NGL (bbl/d)	239	79	57	56	17
Gas (mcf/d)	10,048	4,261	6,421	4,476	520
BOE (boe/d)	3,436	2,198	2,098	1,122	181
Avg basic shares outstanding	25.89	21.24	19.64	15.44	9.05
Production/Avg mm basic shares	132.8	103.5	106.8	72.7	20.0
Field Price Realizations					
Heavy oil (\$/bbl)	71.58	41.18	38.35	27.44	N.A.
Light and medium oil (\$/bbl)	95.86	70.69	64.46	64.95	46.42
NGL (\$/bbl)	74.15	60.00	61.35	56.19	41.36
Gas (\$/mcf)	8.72	6.96	7.07	10.22	6.72
BOE (\$/boe)	63.73	44.93	43.27	55.85	43.02

(1) Funds from operations and funds from operations per boe and per share are not terms under generally accepted accounting principles (GAAP), and represent cash generated from operating activities before changes in non-cash working capital. Rock considers these are key measures as they demonstrate the Company's ability to generate the cash necessary to fund future growth through capital investment. Funds from operations may not be comparable with the calculation of similar measures for other companies. Funds from operations per share is calculated using the same share basis which is used in the determination of net income/(loss) per share.

(2) Excludes acquisitions and dispositions activity.