



August 25, 2009

Management's Discussion and Analysis

Greentree Gas & Oil Ltd. ("Greentree" or the "Company") is a Canadian-based oil and natural gas company whose common shares are traded on the TSX Venture Exchange (TSX-V) under the symbol "GGO".

The Company's business is the acquisition, exploration, development and operation of oil and gas properties. To date, the Company has conducted all of its activities in the province of Ontario, Canada.

The following Management's Discussion and Analysis (MD&A) was prepared August 25, 2009 and should be read in conjunction with the unaudited consolidated financial statements for the six-month period ended June 30, 2009 together with the notes thereto and the MD&A and audited consolidated financial statements for the year ended December 31, 2008. The reader should be aware that historical results are not necessarily indicative of future performance. The Company's interim financial statements were prepared by management and were not reviewed by Greentree's external auditors. Additional information relating to Greentree can be found at www.sedar.com and www.greentreegas.on.ca

This MD&A contains certain forward-looking statements. Forward-looking statements include, without limitation, any statement that may predict, forecast, indicate or imply future results, performance or achievements. Forward looking statements may be identified, without limitation, by the use of such words as "anticipates", "expects", "intends", "plans", "predicts", "projects", "believes" or words or phrases of similar meaning. In addition, any statement that may be made concerning future performance, strategies or prospects and possible future corporate activities are also forward-looking statements. Forward-looking statements are based on the Company's expectations and are subject to a number of risks and uncertainties that could materially affect the results. Actual results achieved during the forward-looking period may differ materially from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the ability to produce and transport crude oil and natural gas to markets; the results of exploration and development drilling and related activities; fluctuation in foreign currency exchange rates; the imprecision of reserve estimates; the ability of suppliers to meet commitments; actions by government authorities including increases in taxes; decisions or approvals of administrative tribunals; change in environmental and other regulations; risks associated with oil and natural gas operations; impact of weather in areas of operation and production; and other factors, many of which are beyond the control of the Company. The Company disclaims any intention or obligation to publicly update or revise any forward-looking statements or information whether as a result of new information, future events or otherwise, except as may be expressly required by applicable securities laws.

The financial data contained herein is presented in Canadian dollars and has been prepared in accordance with Canadian Accepted Accounting Principles ("GAAP"). In conformity with Canadian Securities Administrators National Instrument 51-101, natural gas volumes have been converted to equivalent barrels of oil ("boe") using a conversion ratio of six thousand cubic feet ("Mcf") to one boe. Readers are cautioned that boes may be misleading, particularly if used in isolation.

NON-GAAP MEASURES

The Company uses certain measures of financial reporting in the MD&A that are commonly used as benchmarks within the oil and natural gas production industry. They are widely accepted measures of performance and value within the industry, and are used by investors and analysts to compare and evaluate oil and natural gas exploration and producing entities.

These measures and their underlying calculations are not defined by Generally Accepted Accounting Principles ("GAAP") in Canada and consequently are referred to as non-GAAP measures. These measures

may not be comparable to a similarly titled measure of another entity. When these measures are used the reader should give them careful consideration.

Included in the MD&A are references to the following non-GAAP terms:

Funds flow from operations, which is determined before changes in non-cash working capital is used as a key measure of performance and liquidity.

Field level cash flow refers to oil and gas sales revenue less royalties, and less operating expenses. It does not include other income or any of the other company expenses that are used to calculate net income.

Operating netback is a benchmark used in the crude oil and natural gas industry to measure the BOE contribution of oil and natural gas sales subsequent to the deduction of royalties, operating and transportation costs.

OVERALL PERFORMANCE

Production for the second quarter of 2009 averaged 96 boe/d a 9% increase from 88 boe/d in the first quarter of 2009 and was a result of a 56% increase in oil production primarily from the Rodney Unit 3 operations. Revenues for the three month period ended June 30, 2009 were \$310,050 as compared to \$310,742 in the first quarter of 2009 and were negatively impacted by a 19% drop in natural gas prices, despite a 100% increase in oil revenues from the first quarter of 2009.

For the three months ended June 30, 2009, the Company had a net loss of \$364,534 (\$0.01 per share) compared to a loss of \$170,520 (\$0.00 per share) for the same period in 2008. For the six months ended June 30, 2009, the Company had a net loss of \$696,321 (\$0.01 per share) compared to a loss of \$390,513 (\$0.01 per share) for the same period in 2008. As a result of recurring losses over the Company's history, the Company has a deficit of \$13.15 million as at June 30, 2009 and has a net working capital deficiency of \$2.94 million at that date. The loss of \$364,534 was a contributing factor in the Company experiencing negative funds flow from operations of \$82,197 for the three months ended June 30, 2009 compared to positive funds flow from operations in the same period in 2008 of \$173,281. This decrease in cash flow from operations was largely due to decreased revenues resulting from much lower commodity prices for oil and natural gas compared to the same period in 2008.

The going concern assumption that the Company will realize the carrying value of its assets and satisfy its obligations as they become due in the normal course of operations will be dependent upon the ability of the Company to raise additional financing to complete various low-risk production opportunities and, to achieve profitable operations sufficient to meet all its obligations.

Bank indebtedness at June 30, 2009 increased to \$1,898,101 from \$1,429,274 at December 31, 2008. The increase of \$468,827 was anticipated as the Company fulfilled its flow-through commitments with the drilling and completion of new oil producers in the Company's Rodney Unit #3 property. Presently, the Company's operating facility agreement requires that the Company meet certain covenants including one relating to an adjusted working capital ratio. As at June 30, 2009, the Company is in violation of the adjusted working capital ratio covenant and the bank has not provided a continuing waiver of the non-compliance.

On June 27, 2008, the Company and the Canada Revenue Agency agreed to an instalment repayment of not less than \$15,000 per month towards arrears commencing in July 2008. During the nine months ended March 31, 2009, all payments were made in accordance with this agreement. In April 2009, the Canada Revenue Agency agreed to a reduced monthly instalment of \$5,000 per month for a three-month period ending June 30, 2009. In July 2009, the Company was unable to make any reduction in the arrears balance. The Canada Revenue Agency and the Company have agreed to review the account on a monthly basis until such time as the Company can demonstrate the ability to make regular instalments towards the arrears balance.

Funds raised in private placements during 2008 allowed the Company to complete a drilling program of 10 development wells in the Rodney Unit #3 pool and one unsuccessful exploration well in the Company's Rodney North prospect area. New oil production was realized in the fourth quarter of 2008 from two new producers placed online. Additional new production was realized in Q2-2009 from two wells placed online late in Q1-2009; the remaining six new oil producers are now on-stream. Production proceeds from the new wells are expected to contribute towards achieving profitable operations.

On August 13, 2009, the Company announced that it intends to undertake a non-brokered private placement to raise additional funding up to \$600,000. The private placement offering will consist of up to \$300,000 of Flow-through units and up to \$300,000 of non Flow-through units. Each Flow-through unit will be priced at \$0.05 and will consist of one (1) flow-through common share and one (1) common share purchase warrant. Each non Flow-through unit will be priced at \$0.04 and will consist of (1) common share and one (1) common share purchase warrant. Each common share purchase warrant will entitle the holder to purchase one common share for \$0.10 within 12 months after closing. The Company will pay finders fees up to 10% of the gross proceeds of the Offering in cash and/or other compensation subject to compliance with regulatory requirements.

RESULTS OF OPERATIONS

During the three months ended June 30, 2009, the Company experienced its lowest level of revenues (net of royalties) in the most recent eight quarters. The continued impact of low commodity prices for oil and gas has significantly raised the level of challenges facing the Company as it attempts to meet the obligations to suppliers and key financial partners.

For the six months ended June 30, 2009, the Company received an average of \$5.73 per Mcf (1,000 cubic feet) for its natural gas production compared to an average of \$10.36 during the same period in 2008. This represents a 45% decline in price for all natural gas production, which represents approximately 84% of the overall boe production mix. Consequently, the natural gas segment of the operation has been the overriding influence on the losses and the overall Corporate financial position.

For the six months ended June 30, 2009, the Company received an average of \$64.04 per barrel for its oil production compared to an average of \$107.66 during the same period in 2008. This represents a 41% decline in price for the Company's oil production, which represents approximately 16% of the overall boe production mix. During the three months ended June 30, 2009, the Company produced approximately 600 barrels more than the preceding quarter and approximately 700 barrels more than the same period in 2008. These increases represent the ongoing results of optimizing oil production from the Rodney Unit #3 property and the Company's overall plan of achieving a greater balance in its production mix. Despite lower oil prices compared to the prior year, the Company continues to realize greater netbacks from its oil production and will continue with its strategy to focus on increasing low-risk oil production.

The Company averaged 96 boe (barrels of oil equivalent) sold per day for the three month period ended June 30, 2009 compared to 90 boe per day for the same period in 2008. During the six month period ended June 30, 2009 the Company averaged 92 boe per day compared to 91 boe per day for the same period in 2008. The increase in both the three and six month period can be attributed to the production arising from the successful infill drilling program in the Rodney Unit #3 area. All new wells are now online and the Company expects to attain higher production levels during in the 3rd quarter once all the wells have cleaned up and the water-flood system has been fully optimized.

During the six months ended June 30, 2009, operating costs (including transportation) reduced to \$187,039 from \$210,460 during the same period in 2008. The reduction during the 2nd quarter of 2009 is a result of cost-containment measures employed throughout 2009 and the positive impact of repairs and maintenance conducted in 2008.

For the six months ended June 30, 2009, general and administrative expenses reduced to \$203,664 compared to \$400,314 during the same period in 2008. For the three months ended June 30, 2009, general and administrative expenses reduced to \$114,035 compared to \$237,727 for the same period in 2008. In both cases, the decrease was largely attributed to lower stock-based compensation costs that occurred in 2008.

For the three and six month periods ended June 30, 2009, interest and other taxes and related interest declined to \$38,277 and \$46,867, respectively, compared to \$73,017 and \$101,692 for the same periods in 2008. The decline can be attributed to the variable rate on the bank indebtedness. The following table will summarize the interest costs by the various type of indebtedness.

(\$) except where indicated	3 Months ended June 30			6 Months ended June 30		
	2009	2008	2007	2009	2008	2007
Bank debt	24,362	33,194	47,126	46,410	73,571	90,586
Convertible debenture	7,779	7,779	-	15,472	15,558	-
Capital lease and notes payable	4,660	5,549	5,319	9,659	10,932	11,978
Other	1,476	345	1,392	1,476	1,631	2,950
	38,277	46,867	53,837	73,017	101,692	105,514
\$/boe	4.40	5.69	6.01	4.39	6.11	6.06

FUNDS FLOW FROM OPERATIONS

(\$)	Three months ended June 30			Six months ended June 30		
	2009	2008	2007	2009	2008	2007
Cash provided by operating activities	16,284	450,885	166,481	(5,273)	428,777	370,792
Change in non-cash working capital	(98,481)	(277,604)	(113,509)	(157,931)	(207,834)	(356,141)
Funds flow from operations	(82,197)	173,281	52,972	(163,204)	220,943	14,651

FIELD LEVEL CASH FLOW

(\$)	Three months ended June 30			Six months ended June 30		
	2009	2008	2007	2009	2008	2007
Oil and natural gas sales	310,050	641,366	504,986	660,889	1,142,182	944,459
Royalty expense	(45,913)	(79,722)	(60,249)	(86,010)	(137,151)	(111,854)
Net sales	264,137	561,644	444,737	574,879	1,005,031	832,605
Operating & transportation costs	(187,039)	(210,460)	(190,087)	(436,920)	(425,482)	(393,624)
Field level cash flow	77,098	351,184	254,650	137,959	579,549	438,981

OPERATING NETBACKS

(\$/boe)	Three months ending June 30			Six months ended June 30		
	2009	2008	2007	2009	2008	2007
Oil sales	70.12	107.68	65.80	64.04	123.71	67.93
Natural gas sales	26.98	62.66	53.00	34.65	71.89	54.97
Total sales	35.63	69.01	54.20	39.70	78.58	56.36
Royalty expense	(5.28)	(8.25)	(6.42)	(5.17)	(9.68)	(6.72)
Operating and transportation expenses	(21.49)	(25.58)	(22.59)	(26.25)	(25.56)	(21.22)
Netback	8.86	35.19	25.19	8.29	43.34	28.42

ROYALTIES

Royalty burdens are exclusively freehold and overriding amounts calculated as a percentage of production revenue dollars. Freehold royalties are paid to landowners at a rate of 12.5% for oil production and on a sliding scale for natural gas production varying between 6% and 12.5%. For the three months and six months ended June 30, 2009, overall royalty rates increased relative to sales revenue due to some top-up

payments related to minimum royalty arrangements. The decrease in royalties on a boe basis in 2009 compared to 2008 and 2007 can be entirely attributed to the relative change in commodity prices experienced during those periods.

	3 Months ended June 30			6 Months ended June 30		
	2009	2008	2007	2009	2008	2007
Royalties expense (\$)	45,913	57,429	51,605	86,010	137,151	111,854
\$/boe	5.28	8.25	6.42	5.17	9.68	6.72
Royalties as a % of sales	14.81%	12.32%	11.93%	13.01%	11.95%	11.84%

All of the Company's production is sold within Canada and revenues are received in Canadian dollars. The commodities produced and sold are sensitive to both worldwide (crude oil) and North American (natural gas) price fluctuations and the Canada/U.S. exchange rate. A decrease in the value of the Canadian dollar positively impacts price realizations. There was a 3.4% decrease in the value of the Canadian dollar versus the U.S. dollar in the first three months of 2009. During the three months ended June 30, 2009, there was a 6.7% increase in the value of the Canadian dollar versus the U.S. dollar and during the six months ended June 30, 2009 the average Canada/U.S. exchange rate was 1.206 compared to an exchange rate of 1.007 for the same six month period in 2008.

SALES ANALYSIS

Segment summary	2009		2008				2007	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Oil sales (\$)	122,361	61,044	84,105	126,869	130,949	121,678	68,017	137,468
Oil volume - bbl	1,745	1,119	1,276	1,076	1,063	1,283	839	1,762
Oil price - \$/bbl	70.12	54.55	65.93	117.87	123.16	94.82	81.06	78.04
Natural gas sales (\$)	187,689	288,586	383,855	478,200	510,670	377,630	325,904	310,308
Natural gas volume - Mcf	41,744	40,950	44,398	42,852	43,030	42,686	44,368	45,703
Natural gas price - \$/Mcf	4.50	7.05	8.65	11.16	11.87	8.85	7.35	6.79

bbl = one barrel of oil cf = ft³ of natural gas M = one thousand

The following table presents the dollar variances for oil, gas and total sales compared to the same period in the prior year as a result of changes in both unit prices and boe production of oil and natural gas.

Variances analysis vs. Prior Year (\$)	Three months ending June 30			Six months ended June 30		
	2009	2008	2007	2009	2008	2007
Oil Sales						
Price variance	(56,964)	53,657	(7,557)	(102,394)	68,647	(9,134)
Volume variance	47,822	12,495	(17,595)	33,172	76,133	(6,119)
Total variance	(9,142)	66,152	(25,151)	(69,222)	144,780	(15,253)
Natural Gas Sales						
Price variance	(322,108)	135,343	57,004	(400,309)	152,611	(34,696)
Volume variance	(5,800)	(59,381)	1,594	(17,496)	(93,934)	(21,941)
Total variance	(327,908)	75,962	58,598	(417,805)	58,677	(56,637)
Total Sales						
Price variance	(379,072)	189,001	49,447	(502,703)	221,259	(43,830)
Volume variance	42,022	(46,887)	(16,000)	15,676	(17,802)	(28,060)
Total variance	(337,050)	142,114	33,447	(487,027)	203,457	(71,890)

Price variance = (price/boe current year - price/boe prior year) x boe production prior year
Volume variance = (boe production current year - boe production prior year) x price/boe current year

Depletion, Amortization & Accretion Expenses

Depletion, amortization and accretion increased slightly to \$282,337 for the three months ended June 30, 2009 from \$271,435 in 2008 due to the influence of higher production volumes on the reserve base creating a slightly higher decline rate compared to the prior year.

(\$) except where indicated	3 Months ended June 30			6 Months ended June 30		
	2009	2008	2007	2009	2008	2007
Depletion	249,097	232,859	266,560	472,827	477,868	507,766
Depreciation and amortization	13,368	16,688	26,252	26,736	33,376	65,103
Accretion - ARO	19,872	21,888	7,043	39,744	43,776	16,079
Total	282,337	271,435	299,855	539,307	555,020	588,948
\$/boe	32.45	32.96	33.47	32.40	33.37	33.80

Asset retirement obligation (ARO)

The fair value of asset retirement obligations is recorded as a liability on a discounted basis when they are incurred, which are typically when the related assets are acquired or installed. Amounts recorded for the related assets are increased by the amount of these obligations. Over time the liabilities will be accreted for the change in their present value and the initial capitalized costs will be depleted and amortized over the useful lives of the related assets.

The undiscounted amount of expected cash flows required to settle the asset retirement obligation is estimated at \$1,841,671 (2008 - \$1,816,720). The liability for the expected cash flows, as reflected in the consolidated financial statements, has been discounted at 9% and includes a 2.0% inflation factor (2.0% - 2008).

Asset retirement obligation, beginning of the period	967,972
Change in estimate	
Liabilities settled	
Asset retirement costs incurred	
Accretion	39,744
Asset retirement obligation, end of the period	<u>1,007,716</u>

Costs attributed to these commitments and contingencies are expected to occur over an extended period of time and are to be funded primarily from the Company's cash provided by operating activities. Over the next 5 years, approximately 40% of the costs will be incurred and the remainder from 2014 to 2042. Although the ultimate impact of these matters on operations cannot be determined at this time, it could be material for any one-quarter or year.

SUMMARY OF QUARTERLY RESULTS

Quarterly information

(\$) except as noted	Three months ended June 30			Six months ended June 30		
	2009	2008	2007	2009	2008	2007
Net revenue	264,137	567,378	444,737	574,879	1,010,765	832,605
Net earnings/(loss)	(364,534)	(170,520)	(161,018)	(696,321)	(390,513)	(475,613)
EPS, basic and diluted	(0.01)	0.00	0.00	(0.01)	(0.01)	(0.01)
BOE Production	8,702	8,235	8,960	16,646	16,633	17,425
Total assets	11,526,256	12,174,321	11,218,001	11,526,256	12,174,321	11,218,001
Bank indebtedness	1,898,101	1,870,165	2,236,116	1,898,101	1,870,165	2,236,116

Selected information for the last eight quarters

\$ except as noted	2009		2008				2007	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Net revenue	264,137	310,742	386,465	562,956	567,378	443,387	342,501	394,803
Net earnings/(loss)	(364,534)	(331,787)	280,874	(113,805)	(170,520)	(219,993)	(48,610)	(221,851)
EPS, basic and diluted	(0.01)	0.00	0.00	0.00	0.00	0.00	0.00	(0.01)
BOE Production	8,702	7,944	8,675	8,218	8,235	8,398	8,234	9,379
Total assets	11,526,256	11,503,869	11,310,827	11,395,102	12,174,321	11,641,545	11,838,823	10,963,032
Bank indebtedness	1,898,101	1,724,357	1,429,274	1,229,730	1,870,165	2,064,090	2,099,470	2,174,639

Net Revenue = Revenue less royalties, **EPS** = Earnings per share, **BOE** = barrel of oil equivalent

Over the past eight quarters Greentree's production volumes have varied from a high of 9,379 boe in Q3-2007 to as low as 7,944 boe in Q1 of 2009. The fluctuation results from a number of variables that include positive response from the initial flush production from new wells and reworks to the negative impact of field depletion and periodic production shutdowns due to equipment failure and weather-related incidents (freeze-ups). Overall, the Company's production continues to show relative stability over the past eight quarters. Greentree's revenue over the past eight quarters, however, demonstrated a much higher degree of variability, which was primarily the result of the high volatility in commodity pricing in both oil and natural gas over the period.

LIQUIDITY AND CAPITAL RESOURCES

The Company's working capital deficiency increased to \$2,937,007 at June 30, 2009 from \$1,923,112 at December 31, 2008. The increase of \$1,013,895 was partially anticipated as the Company fulfilled a large percentage of its flow-through commitments with the ongoing completion of the new oil wells in the Unit #3 area resulting in increased bank debt and trade accounts payable. In addition, the Company continued to experience losses resulting from extremely low prices for its natural gas production. This particular influence on liquidity continues to be of great concern to the Company as natural gas production represents the majority of overall production.

As at June 30, 2009, the Company had \$26,899 available from its revolving credit facility. The Company's accounts payable and accrued liabilities will come due within 90 days of the balance sheet date. Given the limited availability of liquid resources together with sustained lower natural gas pricing, the Company anticipates having some difficulty in meeting its short-term obligations. In this regard, communication with suppliers is ongoing so that mutually agreeable arrangements for repayment of trade payable balances can occur over an extended period taking into consideration the cash generated from production revenue.

The Company operates within the terms and conditions of a bank facility that was renewed on October 30, 2008. The facility provides Greentree with a \$1,925,000 revolving demand loan bearing interest payable monthly at the bank's prime lending rate plus 3.00%. As at June 30, 2009, the bank's prime lending rate was 2.25 %.

The facility is collateralized by a \$10 million debenture with a floating charge over all assets of the Company with a negative pledge and undertaking to provide fixed charges on the Company's major producing petroleum and natural gas reserves at the request of the lender, a general assignment of book debts, insurance assignment showing the lender as first loss payee, an assignment of revenues and monies under material contracts, and a guarantee from Southwest Petroleum Explorations Inc., supported by debenture security.

On June 27, 2008, the Company and the Canada Revenue Agency agreed to an instalment repayment of not less than \$15,000 per month towards arrears commencing in July 2008. During the nine months ended March 31, 2009, all payments were made in accordance with this agreement. In April 2009, the Canada

Revenue Agency agreed to a reduced monthly instalment of \$5,000 per month for a three-month period ending June 30, 2009. All payments were made in accordance with this amendment to the original agreement. In July 2009, the Company was unable to make any reduction in the arrears balance. The Canada Revenue Agency and the Company have now agreed to review the account on a monthly basis until such time as the Company can demonstrate the ability to make regular instalments towards the arrears balance.

On August 13, 2009, the Company announced that it intends to undertake a non-brokered private placement to raise funding up to \$600,000. The private placement offering will consist of up to \$300,000 of Flow-through units and up to \$300,000 of non Flow-through units. Each Flow-through unit will be priced at \$0.05 and will consist of one (1) flow-through common share and one (1) common share purchase warrant. Each non Flow-through unit will be priced at \$0.04 and will consist of (1) common share and one (1) common share purchase warrant. Each common share purchase warrant will entitle the holder to purchase one common share for \$0.10 within 12 months after closing. The Company will pay finders fees up to 10% of the gross proceeds of the Offering in cash and/or other compensation subject to compliance with regulatory requirements.

COMMITMENTS AND CONTRACTUAL OBLIGATIONS

Flow through share commitments

Pursuant to the terms of private placements that closed during the year ended December 31, 2008, the Company had a remaining obligation to incur \$652,080 in qualified exploration and/or development expenditures by December 31, 2009. As at June 30, 2009 the Company has fulfilled this commitment.

Office lease commitments

Pursuant to an operating lease agreement, the Company is obligated to make future minimum lease payments of \$1,191 per month (excluding additional rent for operating cost recoveries) until August 1, 2010.

Other Indemnifications

In the ordinary course of business, the Company and its subsidiaries enter into contracts which contain indemnification provisions, such as loan agreements, confidentiality agreements, purchase contracts, service agreements, licensing agreements, asset purchase and sale agreements, joint venture agreements, operating agreements, leasing agreements, land use agreements, and others. In such contracts, the Company may indemnify counterparties to the contracts if certain events occur. These indemnification provisions vary on an agreement by agreement basis. In some cases, there are no pre-determined amounts or limits included in the indemnification provisions and the occurrence of contingent events that will trigger payment under them is difficult to predict. Therefore, the maximum potential future amount that the Company could be required to pay cannot be estimated.

OFF-BALANCE SHEET ARRANGEMENTS

The Company does not have and is not expected to have during its 2009 fiscal year any off-balance sheet arrangements.

RELATED PARTY TRANSACTIONS

During the six months ended June 30, 2009, the following transactions occurred in the normal course of business between the Company and a law firm of which a director and shareholder of the Company is an executive officer and shareholder of the law firm.

	2009
<i>Transactions during the period:</i>	(\$)
Balance due to related party, beginning of period	107,651
Administrative expenses incurred	24,499
Directors' fees incurred	7,088
Payments made during the period	-
Balance due to related party, end of period	139,238

During the six months ended June 30, 2009, the following transactions occurred in the normal course of business between the Company and non-management directors of the Company, excluding those noted above.

	2009
<i>Transactions during the period:</i>	(\$)
Directors' fees due to non-management directors, beginning of period	20,250
Directors' fees recorded (excl. fees noted above)	12,000
Due to non-management directors	32,250

	2009
<i>Transactions during the period:</i>	(\$)
Notes payable due to non-management directors, beginning of period	15,000
Issued during the period	-
Payments made during the period	-
Notes payable due to non-management directors, end of period	15,000

The notes payable are unsecured and payable on demand with interest payable monthly at the rate of 12% per annum.

These transactions were recorded at the exchange amount, which is the amount agreed to by the transacting parties. The balances are included in accounts payable and accrued liabilities in the consolidated balance sheets.

Transactions with directors/shareholders

On September 28, 2007, a non-brokered private placement of convertible debentures was closed in the amount of \$260,000. Included in the total is an amount of \$250,000 received from an individual related to a Director of the Company.

CAPITAL EXPENDITURES

Gross capital expenditures totalled \$771,610 during the six months ended June 30, 2009 compared to \$153,980, in 2008. The change in oil and gas properties for the period is summarized below:

Six months ended June 30 (\$)	2009	2008
Canadian expenditures:		
Lease and land acquisitions	9,366	14,630
Geological & geophysical	66,000	66,000
Drilling, completion and workovers	696,244	66,718
Equipping and facilities		
Other Capitalized amounts		6,632
Asset retirement obligation adjustment		
Canadian Expenditures	771,610	153,980

The Company's capital expenditure program throughout 2009 relates to the drilling, completion and tie-in costs of 10 development wells in the Rodney Unit #3 pool initially commenced in 2008. Greentree's drilling program is located in a relatively undeveloped section of the pool situated between the developed portion of Unit 3 and Taqa North's Rodney Units 1 & 2. Most of the drilling was conducted in the first quarter while completion and testing occurred during the second quarter of 2009. The initial test rates varied between seven and twenty barrels per day per well. The initial test results are consistent with the test rates reported from the original wells in the pool that were drilled in the 1950's. The test results, although encouraging, are very preliminary and the longer-term rates will not be quantified until the wells have been placed on production and monitored for a period of time. Pipeline tie-ins, hook-up to the power grid and final inspection have been completed. As a result of the hook-up process, a significant portion of the pool was shut-in and this had an adverse impact on production.

Greentree would also like to recomplete a number of existing producers in the Rodney Unit 3 pool to exploit potential unrecovered reserves in the upper Devonian pay section. This program will depend upon the Company's ability to raise sufficient capital to undertake the potential projects.

Greentree was not active in the Company's other project areas during the first and second quarters of 2009.

BUSINESS RISKS

The Company is engaged in the exploration, development and production of crude oil and natural gas. The oil and natural gas industry is highly competitive. In addition, the Company is exposed to a number of risks including:

Commodity price risk

The Company is exposed to risks related to fluctuations in the market price for the sale of natural gas and crude oil. During the period, the Company did not attempt to manage this risk with any derivative financial instruments.

Foreign currency risk

The Company is exposed to fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Natural gas and crude oil prices are based upon reference prices that are denominated in U.S. dollars. During the period, the Company did not attempt to manage this risk with any derivative financial instruments.

Interest rate risk

The Company is exposed to interest rate risk arising from fluctuations in interest rates on its operating facility. The floating rate debt is based on the bank's prime lending rate plus 3%. As at June 30, 2009,

the resulting increase or decrease in net earnings for each 1% change on floating rate debt is approximately \$19,000 annually (\$19,000 - 2008).

Credit risk

The Company is exposed to financial risk that arises from the credit quality of the entities to which it provides its natural gas, crude oil, other by-products and services. Credit risk arises from the possibility that the entities to which the Company provides these commodities and services may experience financial difficulty and be unable to fulfill their obligations. Substantially all of the Company’s oil revenues are from one customer and all of the Company’s gas revenues are from one other customer. Approximately 92% of accounts receivable are from these two customers. All of the accounts receivable balances are unsecured and, as such, the entire balance in accounts receivable represents the Company’s maximum exposure to credit risk.

Liquidity risk

Liquidity risk represents the risk that the Company will not be in a position to meet its financial obligations as they come due. As at June 30, 2009, the Company had \$26,899 available from its revolving credit facility. The Company’s accounts payable and accrued liabilities will come due within 90 days of the balance sheet date. Given the limited availability of liquid resources, management anticipates having some difficulty in meeting the Company’s short-term commitments. As a result, management has undertaken an initiative to carry out discussions with its suppliers in an effort to align the maturity of trade debt with cash generated from production revenue. In respect of the maturity profile of all the Company’s financial instruments, the bank loan is due on demand while accounts payable and accrued liabilities generally mature within 3 months of the balance sheet date.

The following table summarizes the estimated timing of financial commitments for the next 5 years:

Item	6 months	2010	2011	2012	2013
Accounts payable and accruals	996,330				
Notes & other payables	15,000				
Income & other taxes payable	90,000	180,000	180,000	93,697	
Long term debt	57,688	93,743	49,430	260,000	

Capital Requirements

The Company anticipates incurring capital expenditures for the exploration, development and production of oil and natural gas reserves in the future. As the Company’s revenues may decline as a result of decreased commodity pricing, it may be required to reduce capital expenditures. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Company to additional access to capital risk. There can be no assurance that debt or equity financings, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt and equity financing is available, that it will be on terms acceptable to the Company. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on Greentree’s business, financial condition, results of operations and prospects.

Exploration Risks

Oil and natural gas exploration involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. The cost of drilling, completing and operating wells may vary significantly from initial estimates. The Company’s drilling operations may be unsuccessful or may be curtailed, delayed or cancelled as a result of numerous factors not within its control. These factors include, but are not limited to, title problems, weather conditions, compliance with governmental requirements, shortage of capital, mechanical difficulties and shortages or delays in the delivery of drilling rigs or other equipment. Accordingly, there can be no assurance that the Company’s acquisition, development, exploitation and exploration activities will result in reserves being added at acceptable costs. There is no assurance that additional oil or natural gas reserves in commercial quantities will be discovered by the Company.

Operating Hazards

The oil and gas business involves a variety of operating risks, including the risk of fire, explosion, blow-out, pipe failure, casing collapse, stuck tools, abnormally pressured formations and environmental hazards such as oil spills, gas leaks, pipeline ruptures and discharges of toxic gases, the occurrence of any of which could result in substantial losses to Greentree due to injury and loss of life, loss of or damage to well bores and drilling or production equipment, costs of overcoming down hole problems, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. Gathering systems and processing facilities are subject to many of the same hazards and any significant problems related to those facilities could adversely affect Greentree's ability to market its production. Insurance may not cover down hole operating risks, such as the costs of retrieving stuck equipment. Furthermore, Greentree cannot predict whether insurance will continue to be available at premium levels that justify its purchase or whether insurance will be available at all to cover the risks faced by the Company.

Global Financial Crisis

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 became evident in the latter part of 2008 and are continuing in 2009, causing a loss of confidence in the broader U.S. and global 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.

Oil and natural gas prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns.

Estimates of Reserves and Related Data

Numerous uncertainties are inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures including many factors beyond the control of the producer. Oil and gas reserve engineering is a subjective process of estimating accumulations of oil and gas that cannot be measured in an exact manner and estimates of other engineers might differ materially from those shown. The accuracy of any reserve estimate is a function of the quality and quantity of available data, engineering and geological interpretation and judgment. In addition, the estimates of future net cash flow from proved reserves of the Company and the present value thereof are based upon certain assumptions about future production levels, prices, costs and participation, if any, by third parties in the development of the Company's reserves that may not prove correct over time for reasons which may or may not be under the control of or known to the Company. Any significant variance from these assumptions could materially affect the quantity and value of the Company's reserves as compared to the estimates contained in this MD&A.

Environmental Regulation

The drilling for and production, handling, transportation and disposal of oil and gas and by-products are subject to extensive regulation under federal, provincial and local environmental laws. In most instances, the applicable regulatory requirements relate to water and air pollution control and solid waste management measures, permitting requirements, or restrictions on operations in environmentally sensitive areas. Environmental assessments have not been performed on all of Greentree's properties. To date, expenditures for environmental control facilities and for remediation have not been significant in relation to the results of operations of Greentree. Greentree believes,

however, that the trend toward stricter standards in environmental legislation and regulation is likely to continue.

Political Risks

The Company's operations are subject to business risk inherent to the oil and natural gas industry. These risks can involve matters arising out of government policies, imposition of special taxes or similar charges by government bodies, foreign exchange fluctuations and controls, access to capital markets, civil disturbances, deprivation or unenforceability of contract rights or the taking of property without fair compensation.

Dependence on Key Personnel

The Company is highly dependent on the continued service of and its ability to attract and retain qualified engineering and management personnel. The competition for such personnel is intense and the loss of particular persons, as well as the failure to recruit additional key personnel in a timely manner, could have a material adverse effect on the Company's business.

Changing Business Conditions

The Company's future operating results will substantially depend on the ability of its officers and key employees to manage changing business conditions and to implement and improve its operational, financial control and reporting systems. If the Company is unable to respond to and manage changing business conditions, the quality of the Company's services, its ability to retain key personnel and its results of operations could be materially adversely affected.

CRITICAL ACCOUNTING ESTIMATES

Oil and Gas Properties

The preparation of consolidated financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

The Company follows the full cost method of accounting for oil and gas operations whereby all costs of exploring for and developing oil and gas reserves are initially capitalized. Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling and overhead charges directly related to acquisition and exploration activities.

Costs capitalized, together with the costs of production equipment, are depleted and amortized on the unit-of-production method based on the estimated gross proved reserves as determined by independent petroleum engineers. Petroleum products and reserves are converted to a common unit of measure, using 6 Mcf of natural gas to 1 Bbl of oil.

Costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations. These unevaluated properties are assessed periodically to ascertain whether impairment has occurred. 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 costs subject to depletion calculations.

Proceeds from sale of petroleum and natural gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would alter the rate of depletion by more than 20%.

The Company applies an impairment test ("ceiling test") to determine if capitalized costs are not recoverable and exceed their fair value. Capitalized costs are not recoverable if they are greater than estimated undiscounted cash flows from future production of proved reserves plus the cost (net of impairment) of unproved properties. Commodity prices used in calculating estimated cash inflows are based on quoted benchmark prices. Costs used in estimating cash outflows are based on expected future

production and other costs and include abandonment and site restoration costs. An impairment loss is recognized if capitalized costs are greater than their recoverable amount. The impairment loss is measured as the amount by which capitalized costs exceed the fair value of proved reserves plus the cost (net of impairment) of unproved properties. Fair value is determined based on the present value of future cash flows, after deducting abandonment and site restoration costs, discounted at a risk free interest rate. Any impairment loss is charged to earnings.

Changes in Accounting Policy including Initial Adoption

The CICA has issued the following new and amended Handbook Sections that became effective for the Company on January 1, 2008:

Amended CICA Handbook Section 1400, "General Standards of Financial Presentation"
CICA Handbook Section 1535, "Capital Disclosures"
CICA Handbook Section 3862, "Financial Instruments - Disclosures"
CICA Handbook Section 3863, "Financial Instruments - Presentation"

The Accounting Standards Board ("AcSB") amended CICA Handbook Section 1400, to include requirements for management to assess and disclose an entity's ability to continue as a going concern. This section applies to interim and annual financial statements relating to fiscal years beginning on or after January 1, 2008. Refer to Note 1 for Going Concern disclosures.

CICA Handbook Section 1535 establishes standards for disclosing information about an entity's capital and how it is managed. The entity's disclosure should include information about its objectives, policies and processes for managing capital and disclose whether or not it has complied with any capital requirements to which it is subject and the consequences of non-compliance. Refer to note 16 for additional disclosures.

CICA Handbook Section 3862 modifies the disclosure requirements for CICA Handbook Section 3861, "Financial Instruments - Disclosure and Presentation", including required disclosure for the assessment of the significance of financial instruments for an entity's financial position and performance and of the extent of risks arising from financial instruments to which the Company is exposed and how the Company manages those risks. CICA Handbook Section 3863 carries forward the presentation requirements of CICA Handbook Section 3861. Refer to note 15 for additional disclosures.

Future accounting pronouncements

The CICA has issued the following new Standards that will become effective for the Company:

- CICA Handbook Section 3064, Goodwill and Intangible Assets; and
- Adoption of International Financial Reporting Standards.

In February 2008, the CICA issued new CICA 3064, Goodwill and Intangible Assets, replacing CICA 3062, Goodwill and Other Intangible Assets, and CICA 3450, Research and Development Costs. New Section 3064 addresses when an internally developed intangible asset meets the criteria for recognition as an asset. The CICA also issued amendments to Section 1000, Financial Statement Concepts, and Accounting Guideline AcG-11, Enterprises in the Development Stage. EIC-27, Revenues and Expenditures during the Pre-operating Period, will not apply to entities that have adopted section 3064. The objectives of the changes are to reinforce a principle-based approach to the recognition of costs as assets and to clarify the application of the concept of matching revenues and expenses in CICA 1000. Collectively, these changes bring Canadian practice closer to International Financial Reporting Standards ("IFRS") and U.S. GAAP by eliminating the practice of recognizing as assets a variety of start-up, pre-production and similar costs that do not meet the definition and recognition criteria of an asset. Consequently, such costs will be expensed as incurred. The effective date of adopting this new standard for the Company is January 1, 2009. This standard will have no effect on the Company's financial statements.

The CICA's Accounting Standards Board has announced that Canadian publicly accountable enterprises will adopt IFRS as issued by the International Accounting Standards Board effective

January 1, 2011 and therefore will commence in the first quarter of the Company's 2011 fiscal year with comparative figures. The Company will be developing a plan for the implementation of IFRS and will assess the impact of the differences in accounting standards on the Company's consolidated financial statements. It is not practically possible at this time to quantify the impact of these differences. The Company expects to make changes to processes and systems before the 2011 fiscal year, in time to enable the Company to record transactions under IFRS for comparative purposes in the 2011 financial year reporting.

Measured Uncertainty

The amounts recorded for depletion and depreciation of oil and gas properties, the provision for future site restoration and abandonment costs and the ceiling test calculation are based on estimates of proven reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the consolidated financial statements of changes in such estimates in future years could be significant.

Financial Instruments

The Company has classified all financial instruments as one of; held-for trading, available-for-sale, held-to-maturity, loans and receivables, or other financial liabilities. Subsequent measurement of changes in the value of financial instruments depends on their initial classification.

Financial assets and liabilities held-for-trading are measured at fair value with changes in those fair values recognized in net income. Derivatives are classified as held for trading and recorded at fair value.

Available-for-sale financial assets are measured at fair value. Revaluation gains and losses are included in other comprehensive income until the assets are removed from the balance sheet.

Financial assets held-to-maturity, loans and receivables and other financial liabilities are measured at fair value and subsequently measured at amortized costs using the effective interest method. Investments in equity instruments classified as available-for-sale that do not have quoted market prices in an active market are measured at cost. The Company has implemented the following classifications:

Accounts receivable and other receivables are classified as loans and receivables. Bank indebtedness, accounts payable and accrued liabilities, the convertible debentures and the note payable, are classified as other financial liabilities and are measured at amortized cost using the effective interest method.

SHARE CAPITAL

Authorized

Unlimited common voting shares without par value.

Issued and outstanding

	2009	
	Shares	Amount (\$)
Common shares	54,038,463	16,262,861