GREENTREE GAS & OIL LTD.

MANAGEMENT'S DISCUSSION AND ANALYSIS

December 31, 2007

The following Management's Discussion and Analysis ("MD&A") was prepared as of April 29, 2008 and should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2007.

In conformity with the Canadian Securities Administrators National Instrument 51-101 ("NI 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.

This MD&A contains forward-looking statements. Forward-looking statements are based on current expectations that involve a number of risks and uncertainties, which could cause actual events or results to differ materially from those reflected in the MD&A. Forward-looking statements are based on the estimates and opinions of Greentree's Management at the time the statements were made.

Greentree Gas & Oil Ltd. ("Greentree" or the "Company") is a junior explorer and producer of natural gas and oil in southwestern Ontario and trades under the symbol 'GGO' on the TSX Venture Exchange. Greentree currently has 46,857,478 shares outstanding.

NON-GAAP MEASURES

CASH FLOW

Included in the MD&A are references to the term "cash flow". This term is not defined by Generally Accepted Accounting Principles ("GAAP") in Canada and consequently is referred to as a non-GAAP measure. Reported amounts may not be comparable to similarly titled measures reported by other companies. Cash flow should not be considered an alternative to, or more meaningful than, cash provided by operating activities as determined in accordance with Canadian GAAP.

NORMALIZED EBITA, OPERATING EXPENSES, AND GENERAL AND ADMINISTRATIVE EXPENSES

Included in the MD&A in some places are references to the term "normalized EBITA", "normalized operating expenses and "normalized general and administrative expenses". These terms are not defined by GAAP in Canada and consequently are referred to as non-GAAP measures. In each case, the intent is to remove the effects of non-regular and non-recurring items from the related GAAP measure. Reported amounts may not be comparable to similarly titled measures reported by other companies and should not be considered an alternative to, or more meaningful than earnings or loss, operating expenses, or general and administrative expenses as determined in accordance with GAAP, respectively.

PRODUCTION, REVENUES AND ROYALTIES

Total revenues for 2007 of $1,787,541 decreased approximately 3% from $1,846,091 in 2006 due mainly to a minor decline in natural gas production and weaker natural gas prices. Total revenues consisted of sales of natural gas, and crude oil, and to a lesser extent, gas processing and transportation revenue, natural gas by-product sales and other miscellaneous revenue. Total production of 35,037 boe in 2007 was up marginally from total production of 34,986 boe in 2006.

NATURAL GAS

Natural gas production decreased by approximately 4% in 2007 to 184,787 mcf as compared to 192,756 mcf for 2006. The minor decrease in production volumes was largely a result of infrastructure changes in the Innerkip sales system by Primewest Energy Trust (operator) which created a market limitation for GGOL#68. In addition the Company has placed a focus on light oil exploitation and development due to the significant premium placed on oil versus natural gas.

In 2007, the average natural gas price received was $7.90 per mcf, which was down 6% from the average of $8.41 per mcf in 2006. Prices appear to be on the rebound and the Company is expecting higher natural gas prices for 2008.

CRUDE OIL

Crude oil production increased from 2,861 bbls in 2006 to 4,239 bbls in 2007. The 48% increase in production was attained in the Rodney South Unit and through improved efficiency in Rodney Unit 3. The increase in production was realized even though the Rodney South Unit was largely shutdown for seven months as the new production facility was constructed, two new horizontal producers were tied-in and eight injection wells were equipped for service. To date Wavefront Energy and Environmental Services have installed all eight "Powerwave" units and the injection system is fully operational. Wavefront will commence earning in the project as of January 1, 2008. In addition to the oil production in Rodney South and Rodney Unit 3, Greentree completed GGOL#71 (Tilbury West) as an oil producer in the fall of 2007. Production revenues from GGOL#71 were not realized until the first quarter of 2008. The Company expects the well to produce approximately 60 bbls/month until a sand fracture treatment can be conducted to potentially increase production volumes.

The average price for the Company's oil in 2007 was $74.78/bbl as compared to $73.92/bbl in 2006. The substantial rise in prices to a record of $116.97/bbbl on April 18, 2008, did not commence until late in the fourth quarter of 2007.

ROYALTIES

Royalties include both freehold and gross overriding payments. Greentree paid out $217,633 in royalties in 2007 as compared to $220,741 in 2006.

OPERATING EXPENSES

Operating expenses of $786,400 in 2007 were up marginally from $764,668 in 2006. The increase was largely attributed to upgrades to Rodney Unit III for supplies (new wellheads) and contractor assistance with the project.

	2006 ($)	2007 ($)	(Increase)/ Decrease ($)	(Increase)/ Decrease (%)
Operating expenses				
Q1	200,149	203,537	(3,388)	(1.7)
Q2	201,597	190,087	11,510	5.7
Q3	174,807	194,759	(19,952)	(11.4)
Q4	188,115	198,017	(9,902)	(5.3)
Total operating expenses	**764,668**	**786,400**	**(21,732)**	**(2.8)**

Per-boe basis				
Q1	22.90	24.04	(1.14)	(5.0)
Q2	21.79	21.22	0.57	2.6
Q3	19.23	20.77	(1.54)	(8.0)
Q4	23.81	24.05	(0.24)	(1.0)
Annual (per boe)	**21.86**	**22.44**	**(0.59)**	**(2.7)**
Production (boe):				
Q1	8,742	8,465		
Q2	9,251	8,960		
Q3	9,092	9,379		
Q4	7,901	8,233		
	34,986	35,037		

GENERAL & ADMINISTRATIVE EXPENSES

Removing the effects of non-regular or non-recurring items (essentially the non-cash expense of stock option compensation of $99,344 recorded in 2007), normalized general and administrative costs for the year ended December 31, 2006 were $443,863 down from $455,844 in the prior year. The significant item of change from 2006 was a reduction of $42,000 in salaries.

	2006 ($)	2007 ($)	(Increase)/ Decrease ($)	(Increase)/ Decrease (%)
Normalized G&A Expenses				
Q1	92,496	134,557	(42,061)	(45.5)
Q2	121,292	122,746	(1,454)	(1.2)
Q3	88,051	99,024	(10,973)	(12.5)
Q4	154,005	87,536	66,469	43.2
Total G&A Expenses [1]	**455,844**	**443,863**	**11,981**	**2.6**
Per-boe basis				
Q1	10.58	15.90	(5.32)	(50.3)
Q2	13.11	13.70	(0.59)	(4.5)
Q3	9.68	10.56	(0.88)	(9.1)
Q4	19.49	10.63	8.86	45.5
Annual (per boe)	**13.03**	**12.67**	**0.36**	**2.8**

DEPLETION AND DEPRECIATION EXPENSES

DEPLETION

The main factors that affect the calculation of depletion are the level of production, net book value of assets subject to depletion, and estimated remaining reserves. Depletion moves in direct proportion to the first two (i.e., the higher the level of production and the higher the average net book value of depletable assets over a given period, the higher the depletion expense). On the other hand, depletion expense is inversely proportional to the average level of estimated proven reserves over a given period (i.e., the higher the level of estimated reserves, the lower the depletion expense. An impairment calculation was performed on the Company's property, plant and equipment at December 31, 2007 in which the estimated undiscounted future net cash flows associated with the proved reserves exceeded the carrying amount of the Company's property, plant and equipment. At December 31, 2006, an impairment of $2,259,569 was recorded.

DEPRECIATION

Because equipment and certain other assets are depreciated on a straight-line basis, depreciation expense for a given class of assets has more of a direct relationship with the average net book value of the related depreciable assets. As the Company uses depreciation rates varying from 10% to 30%, fluctuations may arise when comparing certain periods.

The following table breaks down the components of depletion and depreciation expenses for the 2007 and 2006 fiscal years.

	2006	**2007**	**(Increase)/Decrease**
	($)	**($)**	**($)**
Depletion	1,156,525	987,525	169,000
Depreciation	49,086	96,197	(47,111)
Write-down	2,296,110	-	2,296,110
Totals	**3,501,721**	**1,083,722**	**2,417,999**

CASH FLOW

Cash flow, as commonly used in the oil and gas industry, represents net income before depletion and depreciation, future income taxes and other non-cash expenses. The difference between "cash flow" and "cash flow from operating activities" is that cash flow represents cash that has been received, or will be received in the future, due to the revenues generated during the period, net of cash that has been paid, or will be paid in the future, as a result of expenses incurred during the period. On the other hand, the latter term measures the actual cash collection and cash payments relating to operating activities that took place during the period. The following table reconciles the Company's cash flow from operating activities to cash flow for the fiscal year ended December 31, 2006 and December 31, 2007.

Year ended December 31,	**2006 ($)**	**2007 ($)**
Cash flow from operating activities, as reported	(827,481)	(406,360)
Changes in non-cash operating working capital items	1,035,878	343,367
Cash flow	208,397	(62,993)

The following table provides quarterly information on the Company's cash flow in comparison to the prior year.

	2006 ($)	2007 ($)	Increase/ (Decrease) ($)
Cash flow			
Q1	129,362	(38,321)	(167,683)
Q2	82,187	52,972	(29,215)
Q3	67,487	1,804	(65,683)
Q4	(70,639)	(79,448)	(8,809)
Total cash flow	**208,397**	**(62,993)**	**271,390**
Per-boe basis			
Q1	14.80	(4.53)	(19.33)
Q2	8.88	5.91	(2.97)
Q3	7.42	0.19	(7.23)
Q4	(8.94)	(9.65)	(0.71)
Annual (per boe)	**5.96**	**(1.80)**	**(7.76)**

CAPITAL EXPENDITURES AND PROJECTS

The Company invested approximately $873,000 in property, plant and equipment during 2007, as compared to $1,743,125 during 2006. Capital expenditures incurred during 2007 consisted primarily of drilling, completion and recompletion costs ($778,000), lease and land costs ($45,000) and equipping, facilities and infrastructure costs ($50,000).

RODNEY SOUTH PROJECT

The “Pilot Phase” of the Rodney South project with Wavefront Energy and Environmental Services Inc. (“Wavefront”) which commenced in September of 2006 has been completed and the injection system was equipped with eight Wavefront “Powerwave” tools. Under the terms of the Wavefront/Greentree Agreement announced February 2, 2006 Wavefront is providing up to $2.25 million in capital expenditures related to the first phase of development. In consideration of Wavefront’s capital investment it shall earn a 70% interest in net earnings from overall production in Rodney South until payout of Wavefront’s initial $2.25 million capital investment. Subsequent to payout, cash flow from operations will be allotted 50% to each of Wavefront and Greentree. Wavefront will begin earning 70% of the net earnings effective January 1, 2008.

The Company has reported that the Wavefront “Powerwave” installations are now fully operational with early water injection results being very encouraging versus non-Powerwave injection data. Production data at the time of writing is indicating that oil volumes are on the increase but until a solid trend develops the Company will not announce the results.

RODNEY UNIT 3 INFILL DRILL PROGRAM

The Company is in the midst of completing a six-well infill drill development program within the Rodney Unit 3 pool. The first well is expected to be online within a month and Greentree is also replacing key production lines in anticipation of additional wells being drilled in 2008. Rodney Unit 3, which is 100% operated by Greentree is part of the Rodney pool which is also comprised of Units 1 and 2, which were recently operated by Primewest Energy Trust (currently being purchased by Abu Dhabi National Energy Company). The Rodney pool (Units 1, 2 & 3) has produced approximately 10.6 million barrels (MMBO) of light oil to date.

Rodney Units 1 and 2 have produced approximately 8.6 MMBO and Rodney Unit 3 has produced 2.0 MMBO to date.

Rodney Units 1 & 2 were developed with a relatively efficient 5-spot and line drive water-flood program as compared to a much less efficient peripheral design, which was implemented in Unit 3. In addition to developing the Unit 3 portion of the Rodney pool with an inefficient water-flood design, significant portions of the pool were left undeveloped. Published engineering reports on Rodney Units 1 & 2 indicated initial oil-in-place reserves of 18.75 MMBO of which 8.6 MMBO have been recovered to date. The recovery factor based on these numbers is approximately 46%. Conversely Rodney Unit 3 has produced approximately 2 MMBO from an estimated initial oil-in-place of 7 MMBO (Greentree internal estimates) or a 28% recovery factor. Using modern injection technologies, design and exploiting the undeveloped areas within Unit 3, Greentree estimates that an additional 1 to 1.5 MMBO may be recoverable from the unit.

NORFOLK COUNTY PROPERTIES

Greentree conducted a sand fracture stimulation treatment on GGOL#50 in Norfolk County prior to Christmas 2007. Initial production data, indicated an approximate 100% increase in natural gas production and the well continues to dewater. With the recent upturn in natural gas prices to over $10 per mcf, the Company will be reviewing various options to increase production in the project area. Production increases may be attained by a number of methods, which include fracture stimulation of existing wells, a workover program, completion of a number of current shut-in wells and new exploration and development drilling. Greentree has maintained a portfolio of leases with the potential to drill over 12 new exploration and development locations.

TILBURY WEST PROSPECT

In 2007, Greentree drilled, cased, completed and conducted an acid fracture stimulation on GGOL#71. On subsequent swab production testing, the well initially indicated to have the potential to produce approximately 25 bbls/d. The well was placed on production and after several months is producing approximately 2 bbls/d of 42 API light oil. The Company believes that with a sand fracture treatment the well may be capable of producing in the 50 to 100 bbl/d range, which is consistent with analogous wells in the region of GGOL#71. Depending of the availability of capital, Greentree plans to conduct the stimulation treatment in 2008.

HALDIMAND COUNTY “DEEP GAS” PROSPECT

Greentree completed the drilling of GGOL#67, a deep wildcat exploration well in late December of 2006. The well encountered 4.2 meters of dolomitized limestone and a gas show in the Ordovician Gull River formation. The Gull River interval was subsequently evaluated with a drill stem test. The down-hole logs indicated dolomite porosity in the 6 to 11% range with relatively high cross-plotted resistivity, which is indicative of the presence of hydrocarbons. The Company has maintained the well as a capped potential gas producer pending additional evaluation. In addition to the natural gas potential in the Gull River formation, Greentree has identified shallow “tight gas” potential in an 18 meter section of sandstone in the Silurian Thorold and Grimsby formations.

Potential has also been indicated in the Ordovician “Blue Mountain-Collingwood formations for “shale gas”. A significant shale gas discovery was recently reported by Forest Oil in the Quebec St. Lawrence Lowlands in the Ordovician “Utica” shale, which is geologically equivalent to the Blue Mountain-Collingwood formations of Ontario. Greentree is currently in the process of renegotiating its existing operating agreement with United States Steel (U.S Steel), which is the owner of the 6,500-acre property. U.S. Steel’s, Lake Erie steel facility is located on the property and uses a very significant amount of natural gas in the steel making process. The plan is to proceed with additional evaluation of the property.

Rodney North Prospect

Greentree is currently drilling an exploration well into a new shallow oil structure which is located along a regional structural trend which hosts the main Rodney pool (Units 1, 2, 3) and the Company's Rodney South pool. Based on geological mapping the structure may be in excess of 300 acres, which would put it in analogous size to Rodney South and the Rodney Unit 3 portion of the main Rodney pool.

LIQUIDITY AND CAPITAL RESOURCES

On January 31, 2007, the Company closed a share-for-debt settlement in which 320,000 common shares were issued to settle an outstanding amount due to a related party of $80,000 less filing fees in the amount of $1,100.

On July 27, 2007, the Company revised its bank credit facilities to include a $1,500,000 operating demand loan and a non-revolving demand loan of $750,000. The Company granted 500,000 share purchase warrants exercisable for a term of 2 years at $0.18 per share as additional compensation for the credit facility.

On September 28, 2007 the Company closed a non-brokered private placement of convertible unsecured debentures. Each debenture bears interest at the rate of 12%, payable quarterly with a maturity date of July 1, 2012. A total of $260,000 was received by the Company of which $250,000 was received from an individual related to a Director of the Company. The debentures are convertible at the option of the holder into common shares of Greentree at $0.24 per share during the first two years, $0.27 during the third year, $0.30 during the fourth year and $0.33 per share in the last year before maturity. The Company may redeem the debentures on thirty (30) days' notice provided that its common shares have traded at prices not less than $0.50 per share in the 30 days immediately preceding the date of such notice if notice is given before July 1, 2009, at $0.55 per share if notice is given in the third year, $0.60 per share if notice given in the fourth year, and $0.65 per share if notice is given in the last year before maturity.

On October 19, 2007, the Company's credit facilities were restructured to include a $1,950,000 revolving operating demand loan and a non-revolving demand loan of $300,000

In December 2007, the Company closed a private placement consisting of three separate tranches during the month. In aggregate, 6,036,217 common shares and 566,625 flow-through shares were issued at $0.11 and $0.15 respectively. Gross proceeds of $748,924 are presented net of share issue costs of $135,477, net of future income taxes of $43,115, and the fair value of warrant costs of $162,338.

As of December 31, 2007 and December 31, 2006 the Company was in violation of its covenant relating to maintaining a minimum working capital ratio. The bank has not waived its right to demand repayment of the outstanding principal balance prior to December 31, 2007 and consequently the entire balance has been shown as a current liability. The loan 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 January 16, 2008, the Company's credit facilities were restructured to consist of a $2,250,000 revolving reducing demand loan. The loan commenced reducing by $50,000 per month on February 1, 2008. The credit facilities are scheduled to be reviewed on or before April 30, 2008.

On April 10, 2008, the Company closed the first tranche of a private placement offering announced on February 26, 2008. The closing consisted of 1,524,999 units at a price of $0.12 per unit for aggregate gross proceeds of $183,000. Each unit consisted of one flow-through common share and one-half of one common share purchase warrant. Each whole warrant issued entitles the holder to purchase one common share of the Company at a price of $0.15 per common share at any time until October 9, 2009. All the securities issued pursuant to the first tranche of the private placement are subject to a four month hold period expiring August 11, 2008. Finder's fees of $12,810 (7% of the gross proceeds of the Offering) are payable in cash to Howco Ventures Inc. and 45,750 common shares were issued to Howco Ventures Inc. (representing 3% of the number of Units sold).

On April 17, 2008, the federal Department of Finance issued a Letter of Demand for the payment of arrears in the amount of $520,273. The demand is related to arrears of amounts owing in respect of income and other taxes payable and the Company has been given fifteen days to either pay the amount in full or respond to the Department of Finance. Greentree has commenced discussion with CRA regarding negotiating a resolution to the matter.

Management is currently in negotiations to raise additional capital in order to fund work on various projects. Steady monthly revenues due to current high oil and natural gas prices enable the Company to continue to meet its ongoing obligations.

RELATED PARTY TRANSACTIONS

During the year, the following transactions occurred in the normal course of business between the Company and a law firm of which a partner is a director and shareholder of the Company.

	2007 ($)	2006 ($)
Balance due to related party, beginning of the year	117,820	335,057
Common shares for debt settlement	(80,000)	(135,000)
Administrative expenses and share issue costs incurred	129,483	36,095
Directors' fees incurred	-	7,213
Payments made during the year	(62,379)	(125,545)
Balance due to related party, end of the year	104,924	117,820

During the year, the following transactions occurred in the normal course of business between the Company and non-management directors of the Company.

Directors' fees	2007 ($)	2006 ($)
Balance due to related parties, beginning of the year	20,500	-
Directors' fees recorded	24,800	20,500
Payments made in respect of directors' fees	(45,300)	-
Balance due to related parties, end of the year	-	20,500

Notes payable	2007 ($)	2006 ($)
Balance, beginning of the year	-	-
Notes payable issued during the year	125,000	-
Accrued interest during the year	1,715	
Payments made in respect of notes payable	(101,715)	-
Balance, end of the year	25,000	-

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 and notes and other payables 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.

ADDITIONAL DISCLOSURES

CRITICAL ACCOUNTING ESTIMATES

Critical accounting estimates require Management to make assumptions regarding matters that are highly uncertain at the time the estimate is made and have a material impact on the financial condition of the Company. A comprehensive discussion of the Company's significant accounting policies may be found in note 3 to the December 31, 2007 consolidated financial statements.

Reserves. The Company's natural gas and oil reserves were evaluated and reported on by the independent petroleum engineering and geological consulting firm of Paddock Lindstrom & Associates, which evaluated the Company's reserves as at December 31, 2007. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change with updated information from the results of future drilling, testing or production levels. Such revisions could be upwards or downwards. Reserve estimates have a material impact on depletion and depreciation expense, asset retirement costs and impairment expense, which could possibly have a material impact on consolidated net income.

Depletion. Capitalized costs and estimated future expenditures to develop proved reserves, including abandonment costs, are depleted based on the proportion of estimated proved oil and natural gas reserves produced during the year compared to total proved reserves. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If it is determined that properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized.

Impairment. In applying the full cost method of accounting, the Company periodically calculates a ceiling, or limitation on the amount that petroleum and natural gas properties may be carried for on the balance sheet. An impairment exists if the undiscounted future net cash flows from proved reserves at future commodity prices plus the cost of undeveloped properties is less than the carrying value of the capitalized costs. If an impairment is found to exist, the impaired properties are written down to their fair value. The fair value of the assets is calculated based on future net cash flows from proved plus probable reserves, discounted at a 10% rate using future commodity prices, plus the cost of undeveloped properties. An impairment may result in a material loss for a particular period; however, future depletion and depreciation expense would be reduced. Assumptions about reserves and future prices are required to calculate future net cash flows. The assumptions made to estimate reserves have been previously discussed. There is significant uncertainty regarding forecasting future commodity prices due to economic and political uncertainty. Future prices are derived from a consensus of price forecasts among recognized reserve evaluators. Estimates of future cash flows assume a long-term price forecast and current operating costs per boe plus an inflation factor. It is difficult to determine and assess the impact of a decrease in proved reserves on impairment. The relationship between reserve estimates and the estimated undiscounted cash flows, and the nature of the impairment test, is complex.

Asset Retirement Obligations. The Company is required to remove production equipment, batteries, pipelines, gas plants and restore land at the end of natural gas and oil operations. The Company estimates these costs in accordance with existing laws, contracts and other policies. These obligations are initially measured at fair value, which is the discounted future value of the liability. These costs are also capitalized as part of the cost of the related assets and amortized over the useful life of the assets.

An annual increase to the liability will be recorded to recognize the passage of time and the impending settlement of the obligation. The liability will be impacted by any changes in the assumptions used in the asset retirement obligation calculation. Adjustments to the estimate will be recorded as an expense on the consolidated statements of earnings.

The asset retirement obligation calculations were derived from typical industry experience and practices. The deemed asset retirement obligation liability for wells and facilities is the sum of the calculated abandonment and reclamation liabilities adjusted for designated status as active, inactive, abandoned, or problem site.

Estimating future asset removal costs is difficult and requires Management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as well as regulatory, political, environmental, safety and public relations considerations. As a result, it is not possible to provide a reasonable analysis of the impact that changes in removal costs would have on the asset retirement obligation.

OPERATIONAL AND FINANCIAL CONDITIONS AND RISKS

Greentree's operations are subject to risks normally associated with the natural gas and oil industry. Oil and natural gas exploration involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that commercial quantities of natural gas and crude oil will be discovered by the Company. The marketability of natural gas and crude oil acquired or discovered will be affected by numerous factors beyond the control of the Company. These factors include reservoir characteristics, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulation.

The Company is exposed to financial risks including interest rate risk on its operating facility, and commodity prices and expenditure costs shifting due to changes in market conditions. Commodity prices are driven by supply, demand and market forces outside the Company's influence. Greentree's ability to raise additional capital will depend upon a number of factors, such as general economic and market conditions that are beyond its control.

QUARTERLY INFORMATION

Quarterly Data *(unaudited)*
Year Ended December 31, 2007

	1st Quarter ($)	2nd Quarter ($)	3rd Quarter ($)	4th Quarter ($)
Gas and oil revenues	437,185	494,427	451,165	385,730
Normalized earnings before interest, taxes, depreciation and amortization (EBITDA)*	(49,726)	131,904	88,420	69,704
Basic & diluted earnings (loss) per share	(0.01)	0.00	(0.01)	0.00
Cash flow**	(38,321)	52,972	1,804	(32,987)
Operating netback per boe***	21.51	27.24	20.89	17.30
Operating and G&A netback per boe****	5.61	13.54	10.33	6.66
Production (boe/d)	94	98	102	89

Quarterly Data *(unaudited)*
Year Ended December 31, 2006

	1st Quarter ($)	2nd Quarter ($)	3rd Quarter ($)	4th Quarter ($)
Gas and oil revenues	543,020	469,813	440,941	373,154
Normalized earnings before interest, taxes, depreciation and amortization (EBITDA)*	185,493	94,268	131,175	(6,098)
Basic & diluted earnings (loss) per share	0.01	(0.01)	0.00	(0.08)
Cash flow**	129,362	82,187	67,487	(70,639)
Operating netback per boe***	31.59	23.11	23.08	17.93
Operating and G&A netback per boe****	21.01	10.00	13.39	(1.56)
Production (boe/d)	97	102	99	86

* Normalized EBITDA (non-GAAP measure) eliminates the effect of unusual, irregular or non-recurring items.
** Non-GAAP measure.
*** Operating netback is calculated as oil and gas revenues less royalties and normalized operating expenses (non-GAAP measure).
****Operating and G&A netback is calculated as oil and gas revenues less royalties, less normalized operating expenses (non-GAAP measure), and normalized general and administrative expenses (non-GAAP measure).

RESPONSIBILITY FOR FINANCIAL STATEMENTS

The accompanying consolidated financial statements for Greentree Gas & Oil Ltd. have been prepared by Management in accordance with Canadian GAAP consistently applied. The most significant of these accounting principles have been set out in the statements. These statements are presented on the accrual basis of accounting. Accordingly, a precise determination of many assets and liabilities is dependent upon future events. Therefore, estimates and approximations have been made using careful judgment. Recognizing that the Company is responsible for both the integrity and objectivity of the consolidated financial statements, Management is satisfied that these consolidated financial statements have been fairly presented.

OUTLOOK

With natural gas prices rebounding to over $10 per thousand cubic feet (mcf) and oil prices touching new highs approaching $120 per barrel, Greentree is positioned to capitalize on this robust energy market.

The Rodney South co-development project with Wavefront is demonstrating increased injectivity, utilizing the eight installed Wavefront “Powerwave” injection tools and oil production is beginning to show positive response to the increased injectivity. The Company is waiting to see a steady trend prior to announcing the results. Success on this “pilot” project will lead to development of the remaining 70% of the mapped extent of the Rodney South pool and Greentree has outlined many other projects of this nature, which include the potential redevelopment of the existing Rodney Unit 3 pool and other shallow oil properties in southwestern Ontario.

The Company is in the midst of completing a six-well infill drill development program within the Rodney Unit 3 pool. The first is expected to be online within a month and Greentree is also replacing key production lines in anticipation of additional wells being drilled in 2008. Geological mapping of the unit has indicated over 25 potential infill locations. The remaining reserve potential of between 1.0 and 1.5 million barrels is very significant at current market prices. The Company believes the upside production potential may be in the order of 15 to 200 barrels per day.

Other oil projects on the books for 2008 include the drilling of the Rodney North prospect and the re-completion of the Tilbury West well. Given the potential mapped extent of the Rodney North structure, the reserves potential may be in the range of 3 to 5 million barrels. The Tilbury West well is currently producing low volumes of light oil but has the potential to produce between 50 and 100 bbls/d with a re-completion.

In terms of natural gas production, Greentree has recently maintained a focus on oil exploitation given the significant premium placed on oil production. With the rebound in natural gas prices the Company will also look at maximizing production in the Norfolk project area through re-completions, workovers and potentially tieing-in some existing shut-in wells. Greentree also has a current inventory of approximately 12 exploration and development wells.

In 2008, Greentree also expects to recommence operations on the United States Steel property in Haldimand County. The 6,500-acre property and surrounding area of mutual interest (AMI) has indicated natural gas potential in multiple horizons, which include “tight gas” and “shale gas” formations. The Company would like to complete the potential Ordovician “Gull River” hydrothermal gas zone in its existing GGOL#67, which is currently a capped potential gas producer and assess both the “tight gas” and “shale gas” intervals.