



## MANAGEMENT'S DISCUSSION AND ANALYSIS

December 31, 2006

The following Management's Discussion and Analysis ("MD&A") was prepared as of April 17, 2007 and should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2006.

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 38,684,247 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 2006 of \$1,846,091 decreased approximately 20% from \$2,308,583 in 2005 due mainly to weaker natural gas prices and reduced oil production. 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 34,986 boe in 2006 was comparable to total production of 35,262 boe in 2005.

#### NATURAL GAS

Natural gas production increased by approximately 6% in 2006 to 192,756 mcf as compared to 182,012 mcf

for 2005. The increase in production is mainly attributable to a new well in Norfolk County and upgrades to the Charlotteville field gathering system.

Lower natural gas prices more than offset the effects of increased production, resulting in 18.2% lower natural gas revenues in 2006 as compared to 2005. The Company received an average price of \$8.41/mcf for its natural gas in 2006, as compared to \$10.89/mcf in 2005.

## CRUDE OIL

Crude oil production decreased from 4,927 bbls in 2005 to 2,861 bbls in 2006. This large decline was attributable to shutdowns of the Rodney Unit 3 and Rodney South Unit; the former in order to implement substantial infrastructure changes and provide refurbished facilities and the latter in order to facilitate sweeping infrastructure changes required for the co-development project with Wavefront Energy and Environmental Systems Inc. (see discussion under "Capital Expenditures and Projects", below).

Crude oil revenues decreased by more than one-third of those posted in 2005 mainly due to the shutdowns described above. Partially offsetting production losses were increased crude oil prices, which continued to climb. The average price for the Company's oil in 2006 was \$73.92/bbl as compared to \$66.00/bbl in 2005.

## ROYALTIES

Royalties include both freehold and gross overriding payments. Royalties as a percentage of gas and oil revenue was approximately 12.1% in 2006 as compared to approximately 11.3% in 2005.

## OPERATING EXPENSES

Operating expenses were higher (approximate 8.3% increase) in 2006 as compared to 2005. Accounting for part of the increase were additional repairs in the Rodney Unit 3 oil field and the reworking of several gas producers to enhance production rates. On a per-barrel equivalency basis, operating costs per barrel of oil equivalent in 2006 were 9.2% higher as compared to 2005.

	2005	2006	(Increase)/ Decrease	(Increase)/ Decrease
	(\$)	(\$)	(\$)	(%)
Operating expenses				
Q1	172,759	200,149	(27,390)	(15.9)
Q2	170,500	201,597	(31,097)	(18.2)
Q3	153,242	174,807	(21,565)	(14.1)
Q4	209,317	188,115	21,202	10.1
Total operating expenses	<b>705,818</b>	<b>764,668</b>	<b>(58,850)</b>	<b>(8.3)</b>

Per-boe basis				
Q1	21.82	22.90	(1.08)	(4.9)
Q2	18.28	21.79	(3.51)	(19.2)
Q3	17.77	19.23	(1.46)	(8.2)
Q4	22.27	23.81	(1.54)	(6.9)
Annual (per boe)	<b>20.02</b>	<b>21.86</b>	<b>(1.84)</b>	<b>(9.2)</b>

## GENERAL & ADMINISTRATIVE EXPENSES

Removing the effects of non-regular or non-recurring items (essentially the non-cash expense of stock option compensation of \$197,600 recorded in 2006), normalized general and administrative costs for the year ended December 31, 2006 were \$455,844, down significantly from \$514,178 in the prior year. On a per-barrel equivalency basis, normalized G&A costs per barrel of oil equivalent in 2006 were 10.6% lower as compared to 2005.

	2005	2006	(Increase)/ Decrease	(Increase)/ Decrease
	(\$)	(\$)	(\$)	(%)
Normalized G&A Expenses*				
Q1	148,568	92,496	56,072	37.7
Q2	140,721	121,292	19,429	13.8
Q3	86,427	88,051	(1,624)	(1.9)
Q4	138,462	154,005	(15,543)	(11.2)
Total Normalized G&A Expenses *	<b>514,178</b>	<b>455,844</b>	<b>58,334</b>	<b>11.3</b>

Per-boe basis				
Q1	18.77	10.58	8.19	43.6
Q2	15.09	13.11	1.98	13.1
Q3	10.02	9.68	0.34	3.4
Q4	14.73	19.49	(4.76)	(32.3)
Annual (per boe)	<b>14.58</b>	<b>13.03</b>	<b>1.55</b>	<b>10.6</b>

\* Non-GAAP measure.

## 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). In accordance with the Company's accounting policies (see Note 3 of the audited consolidated financial statements for the year ended December 31, 2006), an impairment loss of \$2,259,569 has been recognized in 2006 based on an impairment test to determine the recoverability of capitalized costs associated with reserves

## 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. For example, a significant percentage increase in depreciation expense may occur if the Company was to purchase a disproportionately larger amount of assets in a higher-rate class.

The following table breaks down the components of depletion and depreciation expenses for the 2006 and 2005 fiscal years.

	2005 (\$)	2006 (\$)	(Increase)/ Decrease (\$)
Depletion	822,240	1,156,525	(334,285)
Depreciation	93,008	49,086	43,922
Write-down	0	2,259,569	(2,259,569)
<b>Totals</b>	<b>915,248</b>	<b>3,465,180</b>	<b>(2,549,932)</b>

## 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, 2005.

Year ended December 31,	2005 (\$)	2006 (\$)
Cash flow from operating activities, as reported	(729,950)	(827,481)
Changes in non-cash operating working capital items	1,175,259	1,035,878
<b>Cash flow</b>	<b>445,309</b>	<b>208,397</b>

Although positive cash flow was posted for 2006, falling natural gas prices and the loss of oil production revenue due to constructing the new Rodney South unit have negatively impacted the company's cash flow per boe in 2006 as compared to 2005. The following table provides quarterly information on the Company's cash flow in comparison to the prior year.

	2005 (\$)	2006 (\$)	Increase/ (Decrease) (\$)
Cash flow*			
Q1	(5,347)	129,362	134,709
Q2	86,029	82,187	(3,842)
Q3	211,733	67,487	(144,246)
Q4	152,894	(70,639)	(223,533)
Total cash flow*	<b>445,309</b>	<b>208,397</b>	<b>(236,912)</b>

Per-boe basis			
Q1	(0.68)	14.80	15.48
Q2	9.22	8.88	(0.34)
Q3	24.55	7.42	(17.13)
Q4	16.27	(8.94)	(25.21)
Annual (per boe)	<b>12.63</b>	<b>5.96</b>	<b>(6.67)</b>

\* Non-GAAP measure.

## CAPITAL EXPENDITURES AND PROJECTS

The Company invested \$1,743,125 in property, plant and equipment during 2006, as compared to \$723,422 during 2005. Capital expenditures incurred during 2006 consisted primarily of drilling, completion and recompletion costs (\$1,137,899), equipping, facilities and infrastructure costs (\$303,321), geological expenditures (\$138,999), lease and land costs (\$93,937), and field equipment and field automotive costs (\$48,569).

### RODNEY SOUTH PROJECT

The first phase of the Rodney South project with Wavefront Energy and Environmental Services Inc. ("Wavefront") commenced in September of 2006. Greentree has successfully completed the drilling of two horizontal producers and eight injection wells. Both horizontal wells penetrated approximately 170 meters (~560 feet) of oil pay. The new wells are currently being integrated into updated facilities including production and injection lines, central tank battery, and injection system. In addition, six of eight vertical and one horizontal production wells that were shut-in since the initiation of development have been reactivated. The two remaining shut-in vertical wells will be reactivated with the start-up of production from the two new horizontal wells which is anticipated shortly. The current operational plan is to produce all wells naturally to establish a stabilized baseline production rate prior to commencing waterflooding. Water injection will be accomplished using Wavefront's Powerwave Process, more specifically, the highly successful solenoid-actuated Dragonfly tool as well as a new mechanically operated waterflood tool known as the "Mantis".

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.

## TILBURY WEST PROSPECT

In late December, 2006 Greentree announced the entering into a farm-out and participation agreement with Liberty Oil and Gas Ltd. ("Liberty") with respect to the drilling of two wells – one in Tilbury West Township, Essex County (GGOL #71) and the other in Aldoborough Township, Essex County (GGOL #72 - discussed below under "West Lorne Prospects"). The Company recently completed the drilling of GGOL#71, a deep light oil prospect in Tilbury West. The well penetrated a dolomite reservoir interval in the Trenton "Sherman Falls" formation and recovered both light oil and natural gas. The well will be cased and undergo a stimulation procedure with production testing to follow. A number of analogous oil producers that are located structurally on strike of GGOL#71 to the northwest reported initial production rates varying between 36 and 200 bbls/d following stimulation.

## HALDIMAND COUNTY "DEEP GAS" PROSPECT

Greentree completed the drilling of GGOL#67 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 results are encouraging and the Company is having the drill stem test results reviewed and is exploring various options to complete the well.

GGOL#67 also penetrated three separate sandstone units with relatively high porosity (15 to 24%) in the upper Cambrian formation. The sandstone units were water saturated, but a large structural high is present in the project area, which may potentially provide an up-dip hydrocarbon trap for the Cambrian sands. The project area encompasses some 6,500 contiguous acres.

## NORFOLK COUNTY PROPERTIES

During the fourth quarter of 2006, Greentree commenced drilling on two wells in Norfolk County targeting the Silurian Thorold formation. The Company placed GGOL #50 on production in mid-December, 2006 at a restricted rate of approximately 40 mcf/d (natural flow). The well initially tested 125 mcf/d with a final shut-in pressure of 675 psig. The well will undergo a sand fracture treatment, which is expected to substantially increase the production rate. Greentree's second exploratory well, GGOL#59 encountered a two-meter thick Thorold sandstone unit with above average porosity for this formation (15 to 18%). Unfortunately formation water was encountered at the base of the unit and after several attempts to shut-off the water inflow, operations on the well were suspended. A third location in Norfolk has been temporarily postponed due to budget considerations.

## WEST LORNE PROSPECTS

In April of 2006, Greentree completed the drilling of its first well of the year. GGOL #70 encountered a natural gas show in the Silurian A-2 formation but did not encounter natural gas in the targeted Silurian Grimsby formation. Due to uneconomic measured volumes in the Silurian A-2 formation, the well was plugged and abandoned.

Greentree spudded GGOL #72 in mid-December, 2006 and completed drilling in March, 2007. The well penetrated approximately 1.5 meters of porous sandstone in the Silurian Grimsby formation, but on subsequent testing the well produced primarily formation water with a minor amount of gas. The well has subsequently been abandoned. The exploratory test proved the presence of a potentially productive trend and future potential may exist in a structurally up dip location.

## LIQUIDITY AND CAPITAL RESOURCES

As at December 31, 2006, the terms of the Company's operating facility consisted of a revolving line of credit for a maximum unrestricted amount of \$2,400,000, with monthly reductions of \$25,000 commencing

January 31, 2007. The Company has pledged as security 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. As at December 31, 2006, the Company is in violation of working capital covenants of its lending institution.

The Company has made some progress in reducing its short-term debt levels during 2006. The statements reflect accounts payable and accrued liabilities of \$1,171,437, however approximately \$245,000 relates to the Rodney South project and is charged-back to Wavefront and approximately \$139,000 of the payables are charged back to Liberty as their share of expenditures towards their farm-in on two wells. The charge-backs are reflected in accounts receivable. Backing out the effects of the charge-backs, the Company's accounts payable and accrued liabilities is approximately \$787,437.

In addition, the Company negotiated a long-term payment arrangement with the Canada Revenue Agency in the second quarter of 2006. As a result, other taxes payable classified as short-term relating to this matter decreased from a level of \$752,102 at December 31, 2005 to \$260,955 as at December 31, 2006.

During 2006 the Company closed two private placements of capital stock on both a flow-through and non-flow-through basis, for gross proceeds totaling approximately \$1.2 million. Details of the private placements are provided in note 10 to the December 31, 2006 consolidated financial statements.

During December 2006 the Company closed a private placement of capital stock on both a flow-through and non-flow-through basis, for gross proceeds totaling \$402,000.

Management is currently in negotiations to raise additional capital in order to fund work on various projects.

## **RELATED PARTY TRANSACTIONS**

A relationship exists between the Company and a law firm of which a partner is a director and shareholder of the Company. During 2006, professional fees of \$40,797 were incurred for services provided by the law firm. The balance due to the law firm as at December 31, 2006 was \$117,820. Subsequent to year-end, on January 31, 2007 the Company completed a shares-for-debt conversion with the law firm in which the Company issued 320,000 common shares at a price of \$0.25 per share to settle \$80,000 owed to the law firm.

Compensation totaling \$27,250 were incurred as directors' fees for non-management directors of the Company. As at December 31, 2006, \$27,250 is due to non-management directors.

## **ADDITIONAL DISCLOSURES**

### **MANAGEMENT'S EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES**

"Disclosure controls and procedures" are controls and other procedures that are designed to ensure both non-financial and financial information required to be disclosed by us in our periodic reports is recorded, processed, summarized and reported within the time periods required. This information is accumulated and communicated to management as appropriate to allow for timely decisions regarding required disclosures.

As indicated in our certifications filed with the OSC, we completed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2006, under the supervision and with the participation of our Management, including our President and CFO. Based on our evaluation, we concluded our disclosure controls and procedures were effective in all material respects.

## INTERNAL CONTROL OVER FINANCIAL REPORTING

The Chief Executive Officer and Chief Financial Officer are responsible for designing internal control over financial reporting or causing it to be designed under its supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. There are inherent weaknesses in the systems of internal control due to the small size of the Company and its inability to segregate incompatible functions, such as generating, recording, approving and reporting transactions. Should the Company grow to make it economically feasible, Management would plan to remediate these weaknesses by expanding the number of individuals involved in the accounting function and by implementing new accounting-related software.

## 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, 2006 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, 2006. 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

<b>Quarterly Data (unaudited)</b>				
<b>Year Ended December 31, 2006</b>				
	<b>1<sup>st</sup> Quarter (\$)</b>	<b>2<sup>nd</sup> Quarter (\$)</b>	<b>3<sup>rd</sup> Quarter (\$)</b>	<b>4<sup>th</sup> Quarter (\$)</b>
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

<b>Quarterly Data (unaudited)</b>				
<b>Year ended December 31, 2005</b>				
	<b>1<sup>st</sup></b>	<b>2<sup>nd</sup></b>	<b>3<sup>rd</sup></b>	<b>4<sup>th</sup></b>
	<b>Quarter (\$)</b>	<b>Quarter (\$)</b>	<b>Quarter (\$)</b>	<b>Quarter (\$)</b>
Gas and oil revenues	400,164	508,033	554,006	834,438
Normalized earnings before interest, taxes, depreciation and amortization (EBITDA)*	35,173	143,052	257,009	393,082
Basic & diluted earnings (loss) per share	(0.01)	(0.00)	(0.00)	(0.03)
Cash flow**	(5,347)	86,029	211,733	152,894
Operating netback per boe***	22.93	30.08	39.46	56.22
Operating and G&A netback per boe****	4.17	14.99	29.43	41.48
Production (boe/d)	87	102	94	102

\* 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).

In 2006, gas and oil revenues show a decreasing trend as natural gas prices and crude oil production declined. An opposite trend was observed in 2005, as natural gas prices reached record levels for the Company in the latter part of that year. EBITDA, cash flow and netbacks generally showed a positive trend during 2005 and downward trend during 2006 largely due to considerable declines in natural gas prices.

## 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

The Company is optimistic that the Rodney South co-development project with Wavefront will be successful and will generate significant additional cash flow. Success on this "pilot" project will lead to development of the remaining 70% of the mapped extent of the Rodney South pool. Greentree has outlined 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.