



MANAGEMENT'S DISCUSSION AND ANALYSIS

June 30, 2006

The following Management's Discussion and Analysis ("MD&A") was prepared as of August 23, 2006 and should be read in conjunction with the unaudited consolidated financial statements for the three-month and six-month period ended June 30, 2006 and the MD&A and audited consolidated financial statements for the year ended December 31, 2005.

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.

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.

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 36,244,577 shares outstanding.

PRODUCTION, REVENUES AND ROYALTIES

On an overall basis, production in Q2-2006 was 9,251 boe as compared to 9,326 boe for Q2-2005. Gross revenues for Q2-2006 of \$471,539 were 7.8% lower than the \$511,323 posted for Q2-2005. However, gross revenues in the first half of 2006 exceeded gross revenues for the same period in 2005 by \$102,669, an increase of 11.2%. Total revenues consisted of sales of natural gas, crude oil, and to a lesser extent, natural gas by-product sales and other miscellaneous revenue.

NATURAL GAS

Natural gas production increased by approximately 4.6% in Q2-2006 to 48,181 mcf as compared to 46,043 in Q2-2005. Production in the first half of 2006 increased by 7.5% as compared to the same period in 2005. The increase in production is attributed to new wells in West Lorne and Innerkip and upgrades to the Charlotteville field gathering system. These increases were offset somewhat by production losses from temporary shutdowns of the Charlotteville gathering system for upgrading and a shutdown and curtailment of production in Innerkip due to a compressor exchange by the operator of the field. In the latter part of Q2-2006 the Company hooked up three wells to the main sales system and production increases are being realized due to the benefit of compression.

A decline in natural gas prices more than offset the effects of increased production, resulting in a decrease in natural gas revenues by 7.3% in Q2-2006 as compared to the same period in the prior year. The Company received an average price of \$7.87/mcf for its natural gas in Q2-2006, compared to \$8.88/mcf in Q2-2005. However, total natural gas revenues for the first half of 2006 exceeded those in the same period of 2005 by \$105,299, an increase of 13.4%.

CRUDE OIL

Crude oil production decreased from 1,652 bbls in Q2-2005 to 1,221 bbls in Q2-2006, a decline of approximately 26%. The decline in production is attributed to shutdowns of the field to replace a main production line and water source pump for the water-flood injection system. Also contributing to the difference in production was the delivery of additional crude oil produced from two of the Company's natural gas wells in Q2-2005.

Due to strong oil prices, crude oil sales only decreased by 8.6%, from \$99,057 in Q2-2005 to \$90,502 in Q2-2006. Crude oil revenues in the first half of 2006 were approximately equal to those for the same period in 2005, at about \$123,000. The average price for the Company's oil in Q2-2006 was \$76.09/bbl as compared to \$62.14/bbl in Q2-2005, an increase of approximately 20.8%.

ROYALTIES

Royalties include both freehold and gross overriding payments. Royalties as a percentage of gas and oil revenue was approximately 11.6% in Q2-2006 as compared to approximately 11.2% in Q2-2005.

OPERATING EXPENSES

Operating expenses were higher (approximate 18.2% increase) in Q2-2006 as compared to Q2-2005. The main causes of the increase were facility and well repairs and an increase in by-product disposal costs. Operating costs in Q2-2006 were approximately equal to Q1-2006 and slightly less than Q4-2005 (3.9% lower). On a per-barrel equivalency basis, operating costs per barrel were slightly reduced as compared to Q1-2006 (4.8% reduction).

GENERAL & ADMINISTRATIVE EXPENSES

General and administrative costs show a marked increase in Q2-2006 due to two items that are generally non-regular or non-recurring – the granting of stock options, resulting in a non-cash expense of \$189,000 (under GAAP, the granting of this compensation is recorded as an expense using a fair-value calculation) and other compensation for outside directors totalling \$23,000, the latter as a result of Compensation Committee decisions reached in Q2-2006. Removing the effects of the above items, normalized general and administrative costs were \$98,292 for Q2-2006, which remains on par with Q1-2006 at \$92,496.

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). As a result of a combination of these factors, depletion expense in Q2-2006 was \$189,774, compared to \$194,296 in Q2-2005, a difference of 2.3%.

DEPRECIATION

Because equipment is 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 were to purchase a disproportionately larger amount of assets in a higher-rate class. Depreciation expense in Q2-2006 was \$12,627, compared to \$24,587 in Q2-2005.

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, or will be, received in the future due to the revenues generated during the period, net of cash that has been, 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 three-month periods ended June 30, 2006 and June 30, 2005.

3-Month period ended:	June 30, 2006 (\$)	June 30, 2005 (\$)
Cash flow from operating activities, as reported	(66,197)	254,434
Changes in non-cash operating working capital items	148,384	(168,405)
Cash flow	82,187	86,029

Management continues to carefully monitor cash flow in order to settle old outstanding accounts, improve its working capital position, and meet commitments. Although cash flow has remained positive, reductions in natural gas prices may slow progress on this front.

CAPITAL EXPENDITURES AND PROJECTS

The Company invested \$227,569 in property, plant and equipment during Q2-2006, as compared to \$320,220 during Q2-2005. Capital expenditures incurred during Q2-2006 consisted primarily of facilities costs (\$97,944), drilling, restimulation and abandonment expenditures (\$62,092), geological expenditures (\$36,000) and lease and other land costs (\$14,602).

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.

Much preparation was required in obtaining necessary agreements and compiling regulatory submissions prior to commencing work on the co-development of the Company’s Rodney South oil pool with Wavefront Energy and Environmental Services Inc (“Wavefront”). Delays in acquiring certain agreements has resulted in revising the timing on the drilling of 8 injection wells and 2 horizontal producers, which is now expected to commence in early September, 2006. Pursuant to the terms of the agreement, Greentree will retain a 30% interest in the production from the Rodney South wells once the first new producing well is drilled, completed, equipped and tied-in, and a 50% interest subsequent to Wavefront recouping its capital investment. The initial phase of the project is being undertaken at no capital cost to Greentree.

The project with the previously announced large industrial user of natural gas is progressing and a drill site has been selected based on 37.5 kilometers of high-resolution 2D seismic data. The project area has multi-zone natural gas potential. Due to an opting-out clause, Greentree will drill the test well location at its sole cost and expense and will earn 100% of the production revenues. The large industrial user has the option to participate 50% in the net revenues from production, but only once 100% of all drilling, completion, equipping and tie-in costs have been recovered by Greentree.

LIQUIDITY AND CAPITAL RESOURCES

As at June 30, 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 no monthly reductions (i.e., required repayments are interest only, but subject to availability, review and the lending institution's right of demand) and bearing interest at prime plus 2% per year. The Company 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.

As at June 30, 2006, trade payables and accrued liabilities were \$667,787, a steady improvement from 3 months prior (\$769,821). During Q2-2006, the Company has continued to meet the terms of payment arrangements entered into with suppliers.

The Company also improved its working capital position by negotiating of a long-term payment arrangement with the Canada Revenue Agency ("CRA") in respect of the tax matter referred to in note 9 to the June 30, 2006 consolidated financial statements. In addition, the CRA granted a request for the cancellation of interest and penalties relating to this issue (see note 16 of the June 30, 2006 consolidated financial statements for details), which Management estimates will provide \$60,000 of relief.

At the time of writing and subsequent to the second quarter of 2006, the Company closed a private placement in mid-July of 2006 and completed the first tranche of another private placement in mid-August of 2006, raising gross proceeds of over \$1 million in that period. Details of the private placements are provided in note 16 to the June 20, 2006 consolidated financial statements. Management's goal is to raise an additional \$2 million in order to fund future drilling projects and reduce debt.

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 Q2-2006, professional fees of \$9,977 were incurred for services provided by the law firm. The balance due to the law firm as at June 30, 2006 was \$285,193.

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 June 30, 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 Dobson Resource Management Ltd., which evaluated the Company's reserves as at December 31, 2005. 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, 2006	1st Quarter (\$)	2nd Quarter (\$)
Gas and oil revenues	543,020	469,813
Normalized earnings before interest, taxes, depreciation and amortization (EBITDA)*	185,493	94,268
Basic & diluted earnings (loss) per share	0.01	(0.01)
Cash flow	129,362	82,187
Operating netback per boe**	31.60	23.12
Operating and G&A netback per boe***	21.22	12.48
Production (boe/d)	97	102

Quarterly Data (unaudited) Year ended December 31, 2005	1st Quarter (\$)	2nd Quarter (\$)	3rd Quarter (\$)	4th Quarter (\$)
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**	23.21	30.43	39.83	56.57
Operating and G&A netback per boe***	4.44	15.34	29.81	41.84
Production (boe/d)	87	102	94	102

Quarterly Data (unaudited) Year ended December 31, 2004	1st Quarter (\$)	2nd Quarter (\$)	3rd Quarter (\$)	4th Quarter (\$)
Gas and oil revenues	393,049	421,100	512,284	530,400
Normalized earnings/(loss) before interest, taxes, depreciation and amortization (EBITDA)*	(17,759)	(263,731)	(245,944)	(46,673)
Basic & diluted earnings (loss) per share	(0.00)	0.01	(0.02)	(0.10)
Cash flow	(18,107)	(322,342)	(292,266)	(80,211)
Operating netback per boe**	12.92	(4.71)	22.74	26.15
Operating and G&A netback per boe***	(2.15)	(32.70)	(23.42)	(5.82)
Production (boe/d)	91	89	114	104

* Normalized EBITDA eliminates the effect of unusual, irregular or non-recurring items.

** Operating netback is calculated as oil and gas revenues less royalties and normalized operating expenses.

*** Operating and G&A netback is calculated as oil and gas revenues less royalties, less normalized operating expenses, and normalized general and administrative expenses.

In Q2-2006, gas and oil revenues decreased from Q1-2005 as a result of lower natural gas prices and lower oil production. Fluctuations in production over the last three years were due to sporadic shut-downs during both those years. EBITDA, cash flow and netbacks generally show a positive trend over the last two years. Despite the decline in prices in 2006, which have resulted in recent downward trends, netbacks and cash flow continue to be positive.

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

In the Company's Q1-2006 MD&A, Management outlined a number of priorities on which it is pleased to report the following progress.

1. Development plans, unit agreements and regulatory submissions have been completed for the Rodney South shallow oil project which is being co-developed with Wavefront Energy & Environmental Services Inc. Commencement of the project is contingent upon approval by the Ontario Ministry of Natural Resources, which regulates oil and natural gas operations in the Province. Approval on the project is expected shortly. The initial "pilot phase" of the operation will entail the drilling of eight injection wells which will be equipped with Wavefront's patented "Deepwave" technology and two horizontal production wells. A drilling rig has been contracted to complete the drilling of the initial phase of the project.
2. An exploratory location has been selected on the large industrial property previously reported based on 37.5 kilometers of high-resolution 2-D seismic data. The primary exploration target is the Ordovician-age Trenton-Black River carbonates at an estimated depth of 1,000 meters. The seismic data defined a deep structure (graben feature), which is interpreted to be analogous to the prolific Trenton-Black River structures in New York State. Talisman Energy has reported natural gas flow rates from these New York discoveries in the range of 2 to 30 million cubic feet per day. Secondary natural gas potential also exists in a number of shallower intervals. The Company is moving forward with a licence to drill application with the goal of drilling the location in Q3-2006, subject to rig availability and funding.
3. In Q1-2006, Management outlined the objective to raise capital to fund an aggressive drilling program. To date approximately \$1 million has been raised and Management is pursuing an additional \$2 million to be directed towards exploration and development of the Company's prospects and properties. The Company recently successfully deepened an existing well to exploit the Silurian Thorold sandstone. A 5.5-meter gas pay interval was perforated and the well is currently being evaluated for a fracture stimulation treatment.
4. The Company continues to build new relationships and pursue new business opportunities. In July, Greentree started processing and transporting natural gas for another operator in Norfolk County. Greentree charges a processing fee and the additional processed volumes have resulted in better operating efficiencies in the system. Recently Management has had discussion with a potential joint venture partner to pool respective land positions in a high-impact project area.