



MESSAGE TO SHAREHOLDERS

In the second quarter of 2010, Emerald Bay continued to move forward with pipeline and facilities operations in Central Alberta, and an asset acquisition with low-risk, oil drilling in Medina County Texas.

Q2 2010 Highlights

◆ **Well optimization in Taylor-Ina Field, South Texas:**

Optimization of the Company's recently purchased property began in Q2. Optimization of the property will be carried out in multiple phases. Multiple leases did not have efficient production lifting equipment to optimize production, and as of this writing we have now entered over 30 wellbores and installed proper lifting equipment. Approximately 50 additional wellbores will undergo various work-overs to maximize their potential. Early results indicate a 25%+ daily production increase.

◆ **In-fill drilling at Taylor-Ina:**

In addition to the optimization plans outlined above the Company has commenced drilling operations of 10 new wells. Drilling locations were surveyed and staked for Phase 1 drilling operations on three separate leases.

◆ **Zavala and Uvalde Counties Texas:** The Company leased approximately 600 acres in Uvalde County to develop Serpentine Plugs located on the property. A nearby Serpentine Plug field, drilled in 1976 by Emerald Bay's consulting engineer has produced close to 300,000 barrels of oil. Emerald Bay has also executed an Option and Right of First Refusal Agreement with The Energy Company of Texas covering an Area of Mutual Interest of approximately 22,000 acres targeting the Eagle Ford formation. This follows-up the company's Eagle Ford work dating back to 2007. 40+ active rigs are now drilling horizontal Eagle Ford Shale in South Texas.

◆ **Chigwell, Alberta:** the Company fracture-stimulated the Glauconitic zone at 5-31-42-25 W4. The well flowed burnable gas at a rate of 10.793E³m³/day through a 12.7mm choke. A plunger-lift production system is currently being installed to handle the liquids.

Focused Growth For 2010

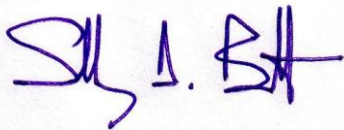
The Company will continue to seek out strategic acquisitions in our core areas, including U.S. opportunities, to grow the Company and add value on significant metrics including cash flow, production and reserves. To provide near-term and long-term stability the Company has transitioned its focus to emphasize oil development opportunities in both Texas and Alberta. Specific areas of growth for the remainder 2010 include:

- ◆ At Gilby, Alberta, the Company recently installed a casing gas compression system that will allow us to produce the condensate liquids more effectively by re-cycling a portion natural gas down the casing, allowing a more consistent flow of gas and liquids up the production tubing. Early indications are that the system trial has now made this well a viable producer for the first time in over 2 years. We will continue to monitor this well extensively during this 60 day trial period, but are very encouraged by the early results.
- ◆ At Twining, Alberta, the Company plans to commingle the Pekisko and Ostracod zones at 16-18-31-23 W4 during the month of September. Poor weather affecting surface conditions have delayed this optimization work-over until early September.
- ◆ At Joffre and Lacombe, Alberta, notwithstanding poor weather conditions, pipeline operations are completed at two locations. Joffre 16-8-39-24 W4 and Lacombe 13-27-41-26 W4 are expected to be perforated and tested over the next 14 days.
- ◆ At Lacombe, Alberta, transportation and processing negotiations are being finalized on 3 wells. Completion operations are expected to begin in June 2010.
- ◆ At Alliance, Alberta, a fracture-stimulation program has been delayed because of recent perforations and production testing. Early indications suggest the well is cleaning up very nicely as daily oil production increases. Similar results have been successful in the surrounding area and avoid the need for a costly stimulation.

In Closing

As the global recession continued, additional downward pressure was placed on natural gas prices throughout the second quarter of 2010. We will continue to focus on managing financial resources to reduce G&A, and operating costs. Cash flow for 2010 will benefit from Emerald Bay's risk management program. We will continue to pursue a carefully designed capital expenditure program, including acquisitions and dispositions, which would allow us to add production, reserves and cash flow in a cost effective manner while maintaining a level of flexibility in our balance sheet.

Best Regards,

A handwritten signature in blue ink, appearing to read 'Shelby Beattie', is written over a light blue rectangular background.

Shelby Beattie, President and Chief Executive Officer

MANAGEMENT'S DISCUSSION & ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with Emerald Bay Energy Inc.'s ("Emerald Bay" or "EBY" or the "Company") unaudited financial statements for the three months ended June 30, 2010 and the audited financial statements for the years ended December 31, 2009 and 2008 together with the accompanying notes. Certain information regarding Emerald Bay contained herein may constitute forward-looking statements under applicable securities laws. Such statements are subject to known or unknown risks and uncertainties that may cause actual results to differ materially from those anticipated or implied in the forward-looking statements. Forward-looking statements are based on the estimates and opinions of EBY's management at the time the statements were made. Emerald Bay assumes no obligation to update forward-looking statements should circumstances or management's estimates change, unless these changes are material to the Company.

Additional information relating to the Company is available on SEDAR at www.sedar.com. Emerald Bay is listed on the Canadian Stock Exchange under the symbol "EBY". The date of this MD&A is August 30, 2010.

BASIS OF PRESENTATION

The Company was incorporated under the Business Corporations Act of Alberta on May 9, 1997 and is listed on the TSX Venture exchange. The Company is engaged in the exploration for and development of petroleum and natural gas properties principally in Alberta and Texas, and is developing a lateral drilling technology.

The financial data presented below has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP").

FORWARD-LOOKING STATEMENTS

Certain information contained herein may constitute forward-looking statements under applicable securities laws. Forward-looking statements look into the future and provide an opinion as to the effect of certain events and trends on the business. Forward-looking statements are based on the estimates and opinions of the Company's management at the time the statements were made. Readers are cautioned not to place undue reliance on these statements as the Company's actual results, performance or achievements may differ materially from any future results, performance or achievements expressed or implied by such forward-looking statements if known or unknown risks, uncertainties or other factors affect the Company's business, or if the Company's estimates or assumptions prove inaccurate. Therefore, the Company cannot provide any assurance that forward-looking statements will materialize.

The Company assumes no obligation to update forward-looking statements should circumstances or management's estimates change, unless these changes are material to the Company.

The material assumptions that were applied in making the forward-looking statements in this MD&A include: execution of the Company's existing plans for each of its projects, which may change due to changes in the views of the Company or if new information arises which makes it prudent to change such plans; and execution of the Company's plans to seek out additional opportunities in the natural resource sector, which are dependent in part on global economic conditions and upon the prices of commodities and natural resources.

BOE PRESENTATION

The term "barrels of oil equivalent" (boe) may be misleading, particularly if used in isolation. A boe conversion of six thousand cubic feet of natural gas to one barrel of oil (6:1) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Readers should be aware that historical results are not necessarily indicative of future performance.

SELECTED QUARTERLY FINANCIAL INFORMATION

	Three months ended June 30			Six months ended June 30		
	2010	2009	Change	2010	2009	Change
FINANCIAL						
Gross revenue	375,183	316,504	18.5%	773,046	700,880	10.3%
Total assets				7,083,572	6,295,952	12.5%
Cash flow from operations	(9,629)	(327,953)	97.1%	(247,007)	(514,612)	52.0%
Per share (basic)	(0.00)	(0.01)	100%	(0.01)	(0.01)	0%
Per share (diluted)	(0.00)	(0.01)	100%	(0.01)	(0.01)	0%
Net income (loss)	(325,281)	(449,787)	-27.7%	(449,073)	(348,038)	29%
Per share (basic)	(0.01)	(0.02)	100%	(0.01)	(0.02)	100%
Per share (diluted)	(0.01)	(0.02)	100%	(0.01)	(0.02)	100%
Capital expenditures	64,626	251,589	74.3%	147,501	639,973	76.9%
Bank debt				2,875,000	2,725,000	5.5%
OPERATIONS						
Production sales						
Oil (bbls/d)	13	15	-13.3%	10	13	-23.1%
Natural gas (mcf/d)	585	606	-3.5%	619	580	6.7%
NGL (bbls/d)	10	11	-9.1%	11	13	-15.4%
Total (boe/d @ 6 mcf: 1 bbl)	121	128	-5.4%	124	123	0.8%
Average pricing						
Natural gas (\$/mcf)	4.51	4.17	8.2%	4.65	5.03	-7.6%
Oil and NGL's(\$/bbl)	63.56	35.54	78.9%	65.40	35.81	82.6%
Combined (\$/boe)	34.13	27.23	25.3%	34.30	31.42	9.2%
Expenses						
Production Expense & transportation (\$/boe)	15.97	16.07	-1.0%	14.17	13.60	4.19%
Royalty expense (\$/boe)	3.60	4.58	-21.4%	6.04	3.69	63.7%
Net Back Combined (\$/boe)	14.56	6.58	121.3%	14.09	14.13	-0.2%

Financial and Operations Results

Revenue from the sale of petroleum and natural gas is recorded on a gross basis when title passes to an external party and is recognized based on volumes delivered to customers at contractual delivery points and rates. The costs associated with the delivery, including production, transportation and production-based royalty expenses are recognized in the same period in which the related revenue is earned and recorded.

Petroleum and natural gas revenue increased 18.5% to \$375,183 for the three months ended June 30, 2010 from revenue of \$316,504 during the three months ended June 30, 2009. The increase was due to slightly higher natural gas prices and significantly higher oil and NGL price which offset a slight decrease in daily production.

Natural gas prices increased 8.2% to \$4.51/mcf in the three months ended June 30, 2010 versus \$4.17/mcf in the three months ended June 30, 2009. Oil and NGL combined prices increased 78.9% to \$63.56 in the three months ended June 30, 2010 from \$35.54 in the three months ended June 30, 2009. The average sales price on a boe basis was \$34.13 in the three months ended June 30, 2010, a 27.3% increase from \$27.23 in the three months ended June 30, 2009.

During the three months ended June 30, 2010, the average sales volume on a boe/d basis decreased by 5.4% to 121 boe/d compared with 128 boe/d for the three months ended June 30, 2009.

During the three months ended June 30, 2010, cash flows from operations increased to \$(9,629) from \$(327,953) in the three months ended June 30, 2009. Natural gas accounted for approximately 81% of the company's total sales during the period with oil and NGL accounting for 19%.

QUARTERLY FINANCIAL INFORMATION

The following is a summary of selected quarterly information that has been derived from the unaudited financial statements of the Company. This summary should be read in conjunction with unaudited financial statements of the Company as contained in the public record.

Emerald Bay Energy Inc.

Quarterly Financial Information (\$000 except per share and unit values)	Jun 30 2010	Mar 31 2010	Dec 31 2009	Sep 30 2009	Jun 30 2009	Mar 31 2009	Dec 31 2008	Sep 30 2008
Petroleum and natural gas sales	375	398	486	301	316	384	382	567
Net income	(325)	(124)	(1,005)	(281)	(450)	102	(420)	(72)
Net income per share								
Basic and diluted	(0.01)	(0.00)	(.03)	(.01)	(.02)	.01	(.02)	.00
Average daily sales								
Natural gas (mcf/d)	585	654	781	668	606	585	561	654
Oil /NGL (bbls/d)	23	19	19	29	26	27	26	31
Barrels of oil equivalent (boe/d)	121	128	149	140	128	124	119	141
Average sales prices								
Natural Gas (\$/mcf)	4.51	4.77	4.36	2.59	4.17	5.68	7.46	9.01
Oil/NGL (\$/bbl)	63.56	67.74	96.22	52.82	35.54	35.39	44.72	76.38
Barrels of oil equivalent (\$/boe)	34.13	34.48	35.47	23.29	27.23	34.35	44.76	58.96
Operating costs (\$/boe)	15.97	12.51	33.92	13.80	16.10	10.33	12.38	17.59
Royalty Expense (\$/boe)	3.60	8.37	6.63	3.25	4.53	2.76	9.08	14.71
Operating netback (\$/boe) ⁽¹⁾	14.56	13.60	(5.08)	6.24	6.60	21.26	23.30	26.66

(1) Operating netback is a non-GAAP measurement equal to revenue less operating costs, transportation and royalties.

Discussion of significant variances

On a quarter by quarter basis production volumes were trending upwards throughout 2009 and into 2010. Unfortunately, during the same time period prices were much lower in 2009 and into 2010 compared to 2008 resulting in lower sales, and the net loss in the quarter is a result of this factor. Production decreased in the first and second quarter of 2010 compared to the fourth quarter of 2009 as significant weather related issues impacted numerous wells in January and February 2010 and projects were delayed in the spring due to severe wet conditions.

CAPITAL EXPENDITURES

Six months ended June 30	2010	2009
Total	147,501	639,973

During the six months ended June 30, 2010, capital expenditures decreased 76.9% to \$147,501 in 2010 from \$639,973 in 2009 as the company dealt with severe wet conditions delaying many projects until Q3 and Q4

LIQUIDITY & CAPITAL RESOURCES

The Company has a \$3,000,000 (December 31, 2009 - \$3,250,000) revolving operating demand loan (the "Revolving Loan"), of which \$2,475,000 (December 31, 2009 - \$2,935,019), has been drawn at June 30, 2010. Interest on the revolving loan is calculated at the bank's prime rate plus 2.00% (December 31, 2009 - bank's prime rate plus 1.50%).

During the three months ended June 30, 2010, the Company obtained a non-revolving demand loan (the "Non-revolving Loan") of \$400,000, through the same bank holding the revolving loan. Interest on the non-revolving loan is calculated at the bank's prime rate plus 2.50%.

As at June 30, 2010, the Company had a negative working capital of \$1,634,750, excluding the bank debt of \$2,875,000 (June 30, 2009 - \$1,073,141 and \$2,725,000 respectively).

The Company is bound by certain debt covenants. The covenants include maintaining a Working Capital Ratio of not less than 1.0 to 1.0 at all times. The Working Capital Ratio for this purpose is defined as Current Assets (including the un-drawn availability under the credit facility) to Current Liabilities (excluding any current portion of bank debt). As at June 30, 2010, the Company was in violation of this bank covenant.

In order to resolve its working capital ratio and to access additional share equity the Company will be emphasizing development of its U.S. properties. The Company's U.S. prospect should produce better returns due to higher oil prices compared with natural gas. While the Company will also focus on optimizing its Canadian based natural gas operations it is critical that, given the recurring operating losses, the Company focuses on an area with the potential growth and positive cash flow that the U.S. prospect has. The Company has received expressions of interest from third parties that will allow the company to meet its capital requirement to pursue this strategy.

In the normal course of operations, the Company enters into contracts and incurs obligations that impact future liquidity.

The annual basic rent obligation is \$65,040 per annum, payable in monthly installments of \$5,420.

RELATED PARTIES

- a) The following amounts are due by related parties:

	June 30, 2010	December 31, 2009
	\$	\$
Note receivable from officer (i)	221,750	218,500
Fair value allowance	(206,710)	(206,710)
Net note receivable	15,040	11,790
Advance fees (ii)	43,429	51,448
	58,469	63,238

- (i) Promissory note bearing interest at 3% per annum and repayable by December 31, 2012 unless the officer's employment is terminated or he is petitioned into bankruptcy wherein the note and accrued interest becomes immediately payable. The note is secured by 393,000 common shares of the Company which had a fair value of \$15,720 at June 30, 2010 (December 31, 2009 - \$35,370).
- (ii) The fair value allowance was determined in 2008, based on the market value at December 31, 2008 of the secured shares. The Company has not provided an allowance to the estimated fair value of the 393,000 common shares held as security as the fair value at June 30, 2010 and December 31, 2009 exceeded the carrying amount.

- (iii) A director was advanced fees in relation to efforts to finance and advance the Company's drilling technology. At June 30, 2010 \$43,429 (December 31, 2009 - \$51,448) remains outstanding. There is no guarantee that such efforts will be successful and if such efforts are not successful, the full balance will be repaid by December 31, 2010.
- b) Except as disclosed elsewhere in the financial statements, the Company was involved in the following related party transactions for the period ended June 30, 2010:

For the three month period ended June 30, 2010:

- (i) Aggregate fees of \$79,275 (June 30, 2009 - \$69,685) were charged by directors and officers of the Company and were expensed as general and administrative expenses.
- (ii) Aggregate legal fees of \$nil (June 30, 2009 - \$2,294) were charged by a law firm in which a director of the Company is a partner, and were expensed as general and administrative expenses.
- (iii) Aggregate fees of \$10,800 (June 30, 2009 - \$27,720) were charged by a U.S. corporation, which is owned and controlled by an officer and a director of the Company for costs it incurred for operation of the Company's U.S. properties. These fees were expensed as general and administrative expenses.

For the six month period ended June 30, 2010:

- (iv) Aggregate fees of \$123,407 (June 30, 2009 - \$173,095) were charged by officers of the Company and were expensed as general and administrative expenses.
- (v) Aggregate legal fees of \$7,854 (June 30, 2009 - \$8,108) were charged by a law firm in which a director of the Company is a partner of, and were expensed as general and administrative expenses.
- (vi) Aggregate fees of \$21,600 (June 30, 2009 - \$27,720) were charged by a U.S. corporation, which is owned and controlled by an officer and a director of the Company for costs it incurred for operation of the Company's U.S. properties. These fees were expensed as general and administrative expenses.
- (vii) Included in accounts payable at June 30, 2010 was \$29,600 owing to related parties of the Company.

Transactions in the normal course of operations are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties

RECENT ACCOUNTING PRONOUNCEMENTS

International Financial Reporting Standards ("IFRS")

In 2006, the Canadian Accounting Standards Board ("AcSB") published a new strategic plan that will significantly affect financial reporting requirements for Canadian companies. The AcSB strategic plan outlines the convergence of Canadian GAAP with IFRS for publicly accountable enterprises over an expected five year transitional period. In February 2008 the AcSB announced that 2011 is the changeover date for publicly-listed companies to use IFRS, replacing Canada's own GAAP. The date is for interim and annual consolidated financial statements relating to fiscal years beginning on or after January 1, 2011. The transition date of January 1, 2011 will require the restatement for comparative purposes of amounts reported by the Company for the year ended December 31, 2010. The Company is currently assessing the impact of the conversion from Canadian GAAP to IFRS on its results of operations, financial position, and disclosures and is in the process of developing an IFRS changeover plan. The plan will include an assessment of differences between Canadian GAAP and IFRS, accounting policy choices under IFRS, internal controls over financial reporting, potential system changes required, potential corporate governance changes and effects on internal controls and processes

including resources and training required for employees. Initial activities include: training sessions for key financial reporting and operation staff; updating the accounting software to include a module to track assets by cash generating unit (“CGU”); and acquisition of written standards and examples of IFRS disclosure. The Company will provide disclosures of the key elements of its plan and progress on the project as the information becomes available during the transition period.

Below is a summary of significant standards under IFRS that may impact the financial statements of the Company. It is intended to highlight those areas the Company believes to be the most significant. The future impacts of IFRS will also depend on the particular circumstances prevailing in future years. The differences as described below, which include, but are not limited to, those existing based on Canadian GAAP and IFRS today.

IFRS 1 - First-Time Adoption of International Financial Reporting Standards provides the framework for the first time adoption of IFRS and specifies in general that an entity will apply IFRS principles retrospectively. IFRS 1 also specifies that the adjustments that arise on retrospective conversion to IFRS should be recognized directly in retained earnings. Certain optional exemptions and mandatory exceptions to retrospective application are provided under IFRS 1. Analysis of the various accounting policy choices is ongoing and will be undertaken in 2010.

Under IFRS, the accounting for activities of the extractive industry (including oil and gas exploration) is governed by IFRS 6 (for the exploration and evaluation phase) and IAS 16 (for development and production phase). Given the early stage of the Company, the transition is not expected to significantly impact the Company.

Under IFRS, the underlying asset retirement obligation (“ARO”) liability may vary from Canadian GAAP given potential variances in the rates used to present value such liabilities. In addition, the unwinding of any present value discount generally will be reflected as a cost of financing under IFRS versus accretion expense under Canadian GAAP. Such differences are not anticipated to materially impact the Company upon transition as currently there is no obligation recorded.

Under IFRS, the asset impairment test is carried out by comparing the asset’s carrying amount with its recoverable amount – being the higher of the asset’s or CGU fair value less costs to sell and its value in use (generally, using discounted cash flows), with the excess of carrying value being recorded as an impairment loss. The sole use of discounted cash flows may result in more frequent write-downs than under Canadian GAAP.

Under IAS 37 – Provisions, Contingent Liabilities and Contingent Assets - the threshold for recognition of these items are generally lower under IFRS than under Canadian GAAP. Accordingly, there may be some contingent liabilities that may require recognition that otherwise may not have been required under GAAP.

The Company has not determined the full accounting effects of adopting IFRS, since key accounting policy alternatives and implementation decisions are currently being evaluated. As the review of accounting policies is completed, appropriate changes to ensure the integrity of internal control over financial reporting and disclosure controls and procedures will be made. Changes in accounting policies may result in additional controls or procedures being required to address first time adoption issues and ongoing IFRS requirements.

Business Combinations, Consolidated Financial Statements and Non-controlling Interest

In January 2009, the CICA issued CICA Handbook Sections 1582: Business Combinations, Section 1601: Consolidations, and Section 1602: Non-controlling Interest. These sections replace the former CICA Handbook Section 1581: Business Combinations and Section 1600: Consolidated Financial Statements and establish a new section for accounting for a non-controlling interest in a subsidiary. CICA Handbook Section 1582 establishes standards for the accounting for a business combination, and states that all assets and liabilities of an acquired business will be recorded at fair value. Obligations for contingent considerations and contingencies will also be recorded at fair value at the acquisition date. The standard also states that acquisition-related costs will be expensed as incurred and that restructuring charges will be expensed in the periods after the acquisition date. It provides the Canadian equivalent to IFRS 3, Business Combinations

(January 2008). The section applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011.

CICA Handbook Section 1601 establishes standards for the preparation of consolidated financial statements.

CICA Handbook Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in the preparation of consolidated financial statements subsequent to a business combination. It is equivalent to the corresponding provisions of IFRS IAS 27, Consolidated and Separate Financial Statements (January 2008).

CICA Handbook Sections 1601 and 1602 apply to interim and annual consolidated financial statements relating to fiscal years beginning on or after January 1, 2011. Earlier adoption of these sections is permitted as of the beginning of a fiscal year.

All three sections must be adopted concurrently.

Equity

In August 2009, the AcSB issued amendments to CICA Handbook Section 3251: Equity as a result of issuing CICA Handbook Section 1602: Non-controlling Interests. The amendments require non-controlling interests to be recognized as a separate component of equity. The amendments apply only to entities that have adopted Section 1602 and are not expected to have an impact on the Company's financial statements.

Comprehensive Revaluation of Assets and Liabilities

In August 2009, the AcSB issued amendments to CICA Handbook Section 1625: Comprehensive Revaluation of Assets and Liabilities for consistency with new CICA Handbook Section 1582: Business Combinations. The amendments apply prospectively to comprehensive revaluations of assets and liabilities occurring in fiscal years beginning on or after January 1, 2011 and are not expected to have an impact on the Company's financial statements.

Accounting changes

In June 2009, the AcSB issued an amendment to CICA Handbook Section 1506: Accounting Changes which is effective for fiscal years beginning on or after July 1, 2009. The amendment excludes from the scope of CICA Handbook Section 1506 changes in accounting policies upon the complete replacement of an entity's primary basis of accounting, as will occur when an entity adopts IFRS.

APPLICATION OF ACCOUNTING ESTIMATES

The significant accounting policies used by Emerald Bay are disclosed in notes to the financial statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Management reviews its estimates on a periodic basis. The emergence of new information and changed circumstance may result in actual results or changes to estimated amounts that differ materially from current estimates.

The Company views the following estimates as critical:

Income Tax

Income taxes are accounted for using the liability method of income tax allocation. Under the liability method, future income tax assets and liabilities are recorded to recognize future income tax inflows and outflows arising from the settlement or recovery of assets and liabilities at their carrying values. Future income tax assets are also recognized for the benefits from tax losses and deductions that cannot be identified with particular assets or liabilities, provided those benefits are more likely than not to be realized. Future income tax assets and liabilities are determined based on the substantively enacted tax laws and rates that are anticipated to apply in the period of realization.

Oil and Gas Properties

The Company follows the full cost method of accounting whereby all costs related to the acquisition are initially capitalized. Costs capitalized include land acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling productive and non-productive wells, together with overhead and interest directly related to exploration and development activities, and lease and well equipment.

Costs capitalized are depleted and amortized on a cost centre basis using the unit-of-production method based on estimated proved petroleum and natural gas reserves before royalties as determined by independent engineers. In determining its depletion base, the Corporation includes estimated future capital costs to be incurred in developing proved reserves and excludes the cost of significant unproved properties until it is determined whether proved reserves are attributable to the unproved properties or impairment has occurred. Unproved properties are evaluated separately for impairment based on management's assessment of future drilling and exploration activities. During the period there has been nil production, and as such a depletion expense was not recognized.

Costs capitalized are periodically assessed for impairment after considering geological data and other information. A loss is recognized at the time of impairment by providing an impairment allowance.

As at June 30, 2010, the Company had oil and gas properties with a net book value of \$ 4,819,388 (December 31, 2009 of \$4,939,889) included in Property, Plant and Equipment on the balance sheet. Impairment of these assets was considered and deemed unnecessary.

Asset Retirement Obligation ("ARO")

The Company will recognize the fair value of an ARO in the period in which a well or related asset is drilled, constructed or acquired and when a reasonable estimate of the fair value can be made. The fair value of the estimated ARO is recorded as a long-term liability, and equals the present value of estimated future cash flows, discounted using a risk-free interest rate adjusted for the Company's credit standing. The liability accretes until the date of expected settlement of the retirement obligations or the asset is sold and is recorded as an accretion expense. The associated asset retirement costs are capitalized as part of the carrying value of the related assets. The capitalized amount is amortized to earnings on a basis consistent with depreciation and depletion of the underlying assets. Actual restoration expenditures are charged to the accumulated obligation as incurred. Any settlements are charged to income in the period of settlement.

Revenue Recognition

Revenue from the sale of petroleum and natural gas is recorded on a gross basis when title passes to an external party and is recognized based on volumes delivered to customers at contractual delivery points and rates and when the significant risks and rewards of ownership have been transferred to the buyer and collectability is reasonably assured.

Financial Instruments, Recognition, Measurement, Disclosure and Presentation

Under Section 3855, all financial instruments are classified into one of the following five categories: held-for-trading; held-to-maturity investments; loans and receivables; available for sale financial assets; or other financial liabilities. All financial instruments and derivatives are measured on the balance sheet date at fair value upon initial recognition. Subsequent measurement depends on the initial classification of the instrument. Held-for-trading financial assets are measured at fair value, with changes in fair value recognized in net earnings (loss). Available for sale financial instruments are measured at fair value, with changes in fair value recorded in Other Comprehensive Income until the instrument is de-recognized or impaired. Loans and receivables, held-to-maturity investments and other financial liabilities are measured at amortized cost.

All derivative instruments, including embedded derivatives, are recorded in the balance sheet at fair value unless they qualify for the normal sales and purchases exemption. Changes in the fair value of derivatives that are not exempt are recorded in net earnings (loss). Derivatives that qualify as hedging instruments must be designated as either a "cash

flow hedge,” when the hedged item is a future cash flow, or a “fair value hedge,” when the hedged item is a recognized asset or liability. The unrealized gains and losses of the effective portion related to a cash flow hedge are included in other comprehensive income. For a fair value hedge, both the derivative and the hedged risk of the hedged item are recorded at fair value in the balance sheet and the unrealized gains and losses from both items are recorded in net earnings (loss). Any derivative instrument that does not qualify for hedge accounting is marked-to-market at each reporting date and the gains or losses are included in income.

Upon adoption of these standards, the Company has designated its cash and cash equivalents as held for trading, which are measured at fair value. Accounts receivable are designated as loans and receivables, which are measured at amortized cost. Accounts payable and accrued liabilities are designated as other financial liabilities, which are measured at amortized cost.

OFF BALANCE SHEET ARRANGEMENTS

The Company is not party to any arrangements that would be excluded from the balance sheet.

FINANCIAL INSTRUMENTS

a) Fair values

The Company’s financial instruments consist of cash and cash equivalents, accounts receivable, the financial contract, the equity investment and accounts payable and accrued liabilities. The fair values of these financial instruments approximate their carrying value due to their short-term nature.

Effective December 31, 2009, the Company adopted the amendments to CICA Section 3862 “Financial Instruments – Disclosures”. These amendments require the Company to present information about financial instruments measured at fair value in accordance with a three level hierarchy. The hierarchy groups financial assets and liabilities into three levels based on the significance of inputs used in measuring the fair values of the financial assets and liabilities. The fair value hierarchy has the following levels:

- (i) Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities;
- (ii) Level 2: inputs other than quoted prices included within Level 1 that are observable for the asset or liability either directly (i.e. as prices) or indirectly (i.e. derived from prices); and
- (iii) Level 3: inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The level within which the financial asset or liability is classified is determined based on the lowest level of significant input to the fair value measurement. At June 30, 2010, the Company’s cash and cash equivalents, the financial contract, and the equity investment have been assessed based on the fair value hierarchy above. Cash and cash equivalents are assessed through level 1, the financial contract through level 2, and the equity investment through level 3. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy.

b) **Credit risk**

The majority of the Company's accounts receivable are due from joint venture partners in the oil and gas industry and from purchasers of the Company's petroleum and natural gas production and are subject to the same industry factors such as commodity price fluctuations and escalating costs. The Company generally extends unsecured credit to these customers and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions. Management believes risk is mitigated by the size and reputation of the companies to which they extend credit. The Company has not experienced any credit loss in the collection of accounts receivable in the period ended June 30, 2010.

Receivables from petroleum and natural gas marketers are normally collected on the twenty-fifth day of the month following production. Receivables related to the sale of the Company's oil and natural gas production are from major marketing companies. The Company historically has not experienced any collection issues with its petroleum and natural gas marketers.

Joint venture receivables are typically collected within one to three months of the joint venture bill being issued to the partner. The Company attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to expenditure and issuing cash calls on large capital projects before they commence.

c) **Market risk**

Market risk is the risk that changes in market prices, such as commodity prices and interest rates, will affect the Company's net earnings or the value of financial instruments. These risks are generally outside the control of the Company.

Commodity price risk

The Company is exposed to commodity price risk on oil and gas revenues. As a means to mitigate the exposure to commodity price volatility, during September 2009 the Company entered into a derivative financial instrument effective January 1, 2010 to December 31, 2010, which collared the received price of natural gas between \$4.53/GJ and \$7.53/GJ for 500 GJ/day.

The Company's derivative financial instruments are classified as held-for-trading and are reported at fair value with changes in fair value recorded through the statement of loss, comprehensive loss, and deficit. The following table summarizes the fair value as at June 30, 2010 and the change in fair value for the three month period ended June 30, 2010:

Financial contract, March 31, 2010	102,060
Unrealized loss	(54,681)
Financial contract, June 30, 2010	<u>47,379</u>

At present, the Company produces primarily natural gas. A \$.50 mcf increase or decrease in the price received for natural gas would result in approximately a \$9,300 increase or decrease in the monthly Petroleum and Natural Gas sales.

Interest rate risk

The Company is exposed to interest rate risk on its revolving loan and non-revolving loan, which have interest rates of prime plus 2.00% and prime plus 2.5%, respectively. An estimated 1% increase or decrease in the interest rate would have affected the Company's statement of operations by \$13,289 for the six months ended June 30, 2010.

d) **Currency risk**

The Company is exposed to the financial risk related to the fluctuation of foreign exchange rates. The Company operates in Canada and the United States and a portion of its expenses are incurred in US dollars. The Company does not hedge its exposure to fluctuations in the exchange rate. Future changes in exchange rates could have a material effect on the Company's business including its intended capital plans, its financial condition and results of operations.

Certain of the Company's financial instruments are exposed to fluctuations in the US dollar, including cash and cash equivalents, accounts receivable and accounts payable and accrued liabilities. As at June 30, 2010, an increase or decrease of 10% to the foreign exchange rate between the US dollar and the Canadian dollar applied to the average level of US denominated cash and cash equivalents would have had approximately a \$5,775 impact on the Company's earnings for the quarter.

e) **Liquidity risk**

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they come due. This may be the consequence of diminished cash flows resulting from lower product prices, production interruptions, or unexpected operating or capital cost increases. Liquidity difficulties could also occur if the Company's bankers were unable to continue to provide credit (when and if applicable) at a level and on terms compatible with the Company's capital requirements. The Company ensures, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, without incurring unacceptable losses or harm to the Company's reputation.

Generally, the Company will, over a reasonable period of time, limit its capital programs to funds flow from operations, available cash and available credit. In addition, the Company endeavors to maintain its debt at a level that will ensure financial flexibility to deal with unforeseen or rapidly changing circumstances.

The Company's net current liabilities and other liabilities and the manner in which they are expected to be met are as follows:

Net working capital deficiency	\$1,634,750	This amount is anticipated to be met out of additional share issuance in the 2010 fiscal period.
Bank debt (Note 8)	\$2,875,000	The Company anticipates issuing additional share capital to reduce this amount in 2010. This amount is secured by the Company's oil and gas assets which have value sufficient such that the Company has no reason to believe that the bank will require repayment within the next fiscal period.
Long term debt	\$101,241	Vehicle loans will be paid over 5 years out of normal cash flow.

OUTSTANDING SHARE DATA

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares issuable in series. As of the date hereof, the Company's issued share capital and the outstanding securities that are convertible into or exercisable or exchangeable for any voting or equity securities of the Company is as follows

Common Shares	50,159,446
Warrants	1,825,000
Stock Options	5,227,500

Notes:

- 1,825,000 of the Warrants entitle the holder to acquire one additional common share for \$0.15 per share until November 20, 2010.
- 1,100,000 of the Stock Options entitle the holders to acquire an equal number of common shares at \$0.25 per share until January 13, 2011. 200,000 of the Stock Options entitle the holders to acquire an equal number of common shares at \$0.17 per share until October 25, 2012. 477,500 of the Stock Options entitle the holders to acquire an equal number of common shares at \$0.08 per share until November 11, 2010. 300,000 of the Stock Options entitle the holders to acquire an equal number of common shares at \$0.10 per share until June 25, 2012. 3,150,000 of the Stock Options entitle the holders to acquire an equal number of common shares at \$0.10 per share until April 6, 2015.

BUSINESS RISKS

The oil and gas industry is subject to risks in (among others):

- Finding and developing reserves.
- Commodity prices received for such reserves.
- Availability of equipment, manpower and supplies.
- Availability and cost of capital to achieve projected growth.
- Effect of weather on drilling and production.
- Operating in an environmentally appropriate fashion.

Emerald Bay mitigates these business risks by:

- Having assets in several diverse fields.
- Maintaining cost-effective operations.
- Maintaining a balance between oil and gas properties.
- Operating our own properties to control the amount and timing of capital expenditures.
- Using new technology to maximize production and recoveries and reduce operating costs.
- Restricting operations to western, central and southern Alberta where locations are accessible, operating and capital costs are reasonable and on-stream times are shorter.
- Drilling wells in areas with multiple high deliverability zone potential.

OUTLOOK

The Company will continue to seek out strategic acquisitions in our core areas, including U.S. opportunities, to grow the Company and add value on significant metrics including cash flow, production and reserves. To provide near-term and long-term stability the Company has transitioned its focus to emphasize oil development opportunities in both Texas and Alberta. Specific areas of growth for the remainder 2010 include:

◆ **Well optimization in Taylor-Ina Field, South Texas:**

Optimization of the Company's recently purchased property began in Q2. Optimization of the property will be carried out in multiple phases. Multiple leases did not have efficient production lifting equipment to optimize production, and as of this writing we have now entered over 30 wellbores and installed proper lifting equipment. Approximately 50 additional wellbores will undergo various work-overs to maximize their potential. Early results indicate a 25%+ daily production increase.

◆ **In-fill drilling at Taylor-Ina:**

In addition to the optimization plans outlined above the Company has commenced drilling operations of 10 new wells. Drilling locations were surveyed and staked for Phase 1 drilling operations on three separate leases.

◆ **Zavala and Uvalde Counties Texas:** The Company leased approximately 600 acres in Uvalde County to develop Serpentine Plugs located on the property. A nearby Serpentine Plug field, drilled in 1976 by Emerald Bay's consulting engineer has produced close to 300,000 barrels of oil. Emerald Bay has also executed an Option and Right of First Refusal Agreement with The Energy Company of Texas covering an Area of Mutual Interest of approximately 22,000 acres targeting the Eagle Ford formation. This follows-up the company's Eagle Ford work dating back to 2007. 40+ active rigs are now drilling horizontal Eagle Ford Shale in South Texas.

◆ **Chigwell, Alberta:** the Company fracture-stimulated the Glauconitic zone at 5-31-42-25 W4. The well flowed burnable gas at a rate of 10.793E³m³/day through a 12.7mm choke. A plunger-lift production system is currently being installed to handle the liquids.

◆ **At Gilby, Alberta,** the Company recently installed a casing gas compression system that will allow us to produce the condensate liquids more effectively by re-cycling a portion natural gas down the casing, allowing a more consistent flow of gas and liquids up the production tubing. Early indications are that the system trial has now made this well a viable producer for the first time in over 2 years. We will continue to monitor this well extensively during this 60 day trial period, but are very encouraged by the early results.

◆ **At Twining, Alberta,** the Company plans to commingle the Pekisko and Ostracod zones at 16-18-31-23 W4 during the month of September. Poor weather affecting surface conditions have delayed this optimization work-over until early September.

◆ **At Joffre and Lacombe, Alberta,** notwithstanding poor weather conditions, pipeline operations are completed at two locations. Joffre 16-8-39-24 W4 and Lacombe 13-27-41-26 W4 are expected to be perforated and tested over the next 14 days.

◆ **At Lacombe, Alberta,** transportation and processing negotiations are being finalized on 3 wells. Completion operations are expected to begin in June 2010.

◆ **At Alliance, Alberta,** a fracture-stimulation program has been delayed because of recent perforations and production testing. Early indications suggest the well is cleaning up very nicely as daily oil production increases. Similar results have been successful in the surrounding area and avoid the need for a costly stimulation.

DATE

This MD&A is dated August 30, 2010.

ADDITIONAL INFORMATION

Additional information regarding this company is available at SEDAR www.sedar.com