Emerald Bay Energy

President's Message

The financial performance for 2010 reflects a year of transition as the exploration and development moved to oil-focused opportunities through its 25% ownership of Production Resources Inc. in South Texas. Natural gas markets remained challenged during the year with prices averaging $4.11, down 1% from 2009. Notwithstanding the economic conditions, Emerald Bay continued to cautiously move forward with pipeline and facilities operations in Central Alberta, and low-risk, oil drilling in Texas.

2010 Highlights

- Acquired 25% of the issued and outstanding securities of Production Resources Inc. ("**PRI**"), a private, Texas based oil company. This was a big step forward in the Company's plans to transition its development to oil properties. The acquisition included existing wells with up-hole potential in by-passed pay zones, and over 100 drilling locations for in-fill drilling. PRI also has the service equipment necessary for a complete, self-sustaining production operation.

- Completed pipeline construction operations for natural gas production at Lacombe, Chigwell, Joffre, and Gilby Alberta.

- Emerald Bay took steps to help secure its CAPEX budget for 2010 by entering into a financial instrument effective January 1, 2010, of 500 GJ/day at a collar band minimum price of $6.00, and a maximum of $9.00.

- Medina County In-fill drilling: Through its 25% ownership of Production Resources Inc. (PRI), and as the managing partner, Emerald Bay has more than 100 in-fill drilling locations on the existing leases in Medina County. PRI completed its 1st ten-well drilling package on three separate leases in the Taylor Ina field. Considering the 175+ existing wells on PRI's leases, a comparative analysis shows each of the wells drilled have either met or exceeded the Company's expectations. All ten drilling permits have been received for the second 10-well program.

- Medina County Well optimization: The PRI well optimization plan was carried out during the 3rd and 4th quarters of 2010. Approximately 40 wellbores received the installation of upgraded lifting equipment. Conventional lifting equipment has been secured to add 5 to 6 wells each week.

- The Company completed a private placement ("Placement A"), issuing 8,850,000 units for total proceeds of $442,500, ($0.05 per unit). Each unit consists of one common share of the Company (issued either as a common share or as a flow-through share (the "FTS")) and one common share purchase warrant (the "Warrant A"). Each whole Warrant entitles the holder to purchase one additional common share of the Company at $0.12 per share, exercisable for 1 year from the date of Placement A. Of the total 8,850,000 units issued, 6,900,000 were issued as a FTS. The Company has allocated $5,863 of the unit value to warrants.

- The Company completed a private placement ("Placement B"), issuing 4,300,000 units for total proceeds of $215,000, ($0.05 per unit). Each unit consists of one common share of the Company (issued either as a common share or as a FTS) and one Warrant A. Of the total 4,300,000 units issued, 1,300,000 were issued as a FTS. The Company has allocated $7,474 of the unit value to warrants.

2011 Highlights and Key Objectives:

- The other two phases of optimization on the PRI assets will be (i) the work-over of the Olmos zone in the existing wells; and (ii) the perforation and production of the by-passed pay zone called the Escondido.

- Under Emerald Bay's direction, PRI has recently tested one well on the Escondido zone with great success. The Olmos zone was isolated; then the Escondido was perforated and put on pump with no stimulation needed. The initial 24-hour test produced 100% oil at rates equivalent to the Company's stimulated Olmos wells. According to plan, the up-hole potential of the existing wellbores has been converted to production very efficiently using Companies-owned equipment.

- The optimization program will continue with a re-stimulation program focused on the Olmos formation. Recent results of an analog field have given us a comfort level necessary to carry out a pilot program of 6 wells in Q2, and then expand that based on results.

- The Company has recently acquired 100% ownership of the Wilson "A" lease from Flinthill Energy, a private, Texas based oil company . The Corporation acquired its 100% working interest in the Wilson A lease for USD$42,625. Under the terms of the purchase agreement, the Corporation will issue, subject to the final approval of the TSX Venture Exchange, 532,812 common shares (at $0.08 per share for aggregate proceeds of $42,625.00) of the Corporation. The strategic 200 acre parcel has a 78% Net Revenue Interest lease that is held by approximately 2 barrels a day of oil production. The lands directly offset wells recently drilled by the Company this past fall. The acquisition of Wilson A lease provides Emerald Bay with quality, low-risk oil assets for future development. The attraction to this particular tract was the proximity to our existing production and the upside of the undrilled, in-fill drilling locations.

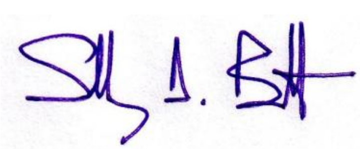
- The Company continues its land and production acquisitions in South Texas with specific focus on Frio, Atascosa, and Medina Counties. Multiple deals are currently in various stages of due diligence and negotiations. Zones of interest will continue to be where the Company has specific experience; such as the Escondido, Olmos, Austin Chalk, Eagle Ford, and Buda. While the Eagle Ford shale is widely considered to be the crown jewel, the Buda has been equally productive for operators who have reached this zone just below the Eagle Ford.

In Closing

In addition to the current pipeline operations in Alberta, and based on the continuation of low natural gas prices, Emerald Bay has transitioned its development focus to oil development in both Texas and Alberta. The initial impact of this transition shows a lower production volume in our overall output. The daily production rates in our PRI affiliate is not reported in Emerald Bay's average daily production rate. These volumes will be periodically reported through press releases after we are confident we have completed our land acquisition efforts in the area.

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. We are confident that we have prepared ourselves to emerge from this environment operationally strong, and we expect to be well positioned to respond quickly when the business environment improves. Our proven management and dedicated team of professionals are engaged and committed to developing our high-quality asset base

Best Regards,



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. ("EBY" or the "Company") audited financial statements for the year ended, December 31, 2010 and the audited financial statements ended December 31, 2009 together with the accompanying notes. Certain information regarding EBY 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.

Additional information relating to the Company is available on SEDAR at www.sedar.com. EBY is listed on the Canadian Stock Exchange under the symbol "EBY". The date of this MD&A is May 2, 2011.

BASIS OF PRESENTATION

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

Application of Accounting Estimates

The significant accounting policies used by EBY are disclosed in note 3 to the audited 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.

Non-GAAP Measures

Management's Discussion and Analysis contains the term "funds from operations", which should not be considered an alternative to, or more meaningful than "cash flow from operating activities" as determined in accordance with GAAP as an indicator of the Company's financial performance. Funds from operations is determined by adding non-cash expenses to the net income or loss for the period, deducting asset retirement expenditures and does not include the change in working capital applicable to operating activities. Management believes that in addition to cash flow from operating activities, funds from operations is a useful supplemental measure as it provides an indication of the results generated by EBY's principal business activities before the consideration of how such activities are financed. The Company's determination of funds from operations may not be comparable to that reported by other companies.

Management's Discussion and Analysis also contains the following terms, which are not considered to be GAAP and may not be comparable to that reported by other companies:

a) "Operating netback" - Operating netbacks are calculated by deducting royalties and operating costs, including transportation costs, from revenues. The Company's determination of operating netbacks may not be comparable to that reported by other companies.

b) "Net debt" – Net debt is calculated by deducting total current liabilities from total current assets.

c) "Working capital" – working capital includes total current assets and total current liabilities. The working capital ratio is calculated by deducting total current liabilities.

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.

FORWARD-LOOKING STATEMENTS

Certain statements contained within the Management’s Discussion and Analysis, and in certain documents incorporated by reference into this document, constitute forward looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward looking statements. Forward looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward looking statements.

In particular, this MD&A contains the following forward looking statements pertaining to, without limitation, the following:

The Company’s future production volumes and the timing of additional production volumes will come on stream; The Company’s realized price of commodities in relation to reference prices; the Company’s future commodity mix; future commodity prices; the Company’s expectations regarding future royalty rates and the realization of royalty incentives; The Company’s expectation of future operating costs on a per unit basis; future general and administrative expenses; future development and exploration activities and the timing thereof; the future tax liability of the Company; the expected rate of depletion, depreciation and accretion; the estimated future contractual obligations of the Company; the future liquidity and financial capacity of the Company; and, The Company’s ability to fund its working capital and forecasted capital expenditures. In addition, statements relating to "reserves" or "resources" are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future.

With respect to the forward looking statements contained in the MD&A, The Company has made assumptions regarding: future commodity prices; the impact of royalty regimes and certain royalty incentives; the timing and the amount of capital expenditures; production of new and existing wells and the timing of new wells coming on-stream; future proved finding and development costs; future operating expenses including processing and gathering fees; the performance characteristics of oil and natural gas properties; the size of oil and natural gas reserves; the ability to raise capital and to continually add to reserves through exploration and development; the continued availability of capital, undeveloped land and skilled personnel; the ability to obtain equipment in a timely manner to carry out exploration and development activities; the ability to obtain financing on acceptable terms; the ability to add production and reserves through exploration and development activities; and, the continuation of the current tax and regulation.

We believe the expectations reflected in those forward looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward looking statements included in, or incorporated by reference into, this MD&A should not be unduly relied upon. These statements speak only as of the date of this MD&A or as of the date specified in the documents incorporated by reference into this Management’s Discussion and Analysis, as the case may be. The actual results could differ materially from those anticipated in these forward looking statements as a result of the risk factors set forth below and elsewhere in this Management’s Discussion and Analysis: which include volatility in market prices for oil and natural gas; counterparty credit risk; access to capital; changes or fluctuations in production levels; liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; stock market volatility and market valuation of The Company’s stock; geological, technical, drilling and processing problems; limitations on insurance; changes in environmental or legislation applicable to our operations, and our ability to comply with current and future environmental and other laws; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry, changes in the regulatory regimes under which the Company operates, changes in the political and social environment that may impact the Company and the other factors discussed under "Risk Factors" in the following annual MD&A. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward looking statements contained in this MD&A and the documents incorporated by reference herein are expressly qualified by this cautionary statement. The forward looking statements contained in this document speak only as of the date of this document and The Company does not assume any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable securities laws.

OPERATING RESULTS

	Average Daily Volumes			Average Prices		
SALES	2010	2009	Percent Change %	2010	2009	Percent Change %
Natural Gas (mcf)	565	661	(14.52)	4.11	4.15	(1.00)
Oil (bbls)	8	12	(33.33)	73.01	65.33	11.76
NGL (bbls)	12	14	(14.29)	55.71	41.44	34.44
Barrels of Oil Equivalent (boe)	114	135	(15.55)	31.43	30.09	4.45

For the year ended December 31, 2010 natural gas sales decreased by 14.52%, to 565 mcf/d from 661 mcf/d the previous year. This decrease was mainly due to certain wells being shut in due to the lower natural gas prices, as well as previously drilled wells not being brought on line until natural gas prices rebound.

Natural gas prices decreased an average of 1.00% during 2010 to $4.11/mcf versus $4.15/mcf during 2009.

Oil production for the year ended December 31, 2010 decreased to 8 bbls/d compared to 12 bbls/d for the year ended December 31, 2009. The variation was due to wells being shut in because of low natural gas prices.

During the year ended December 31, 2010, the average price received for oil was $73.01/barrel versus $65.33/barrel during the previous year, a 11.76% increase. Most of EBY's production is medium viscosity crude which receives higher pricing.

During the year ended December 31, 2010, NGL sales decreased 14.29% to 12 bbls/d compared to 14 bbls/d in 2009.

The average NGL price rose 34.44% to $55.71/bbl compared to $41.44/bbl received in 2009.

During the year ended December 31, 2010, the average sales volume on a boe/d basis decreased by 15.55% to 114 boe/d compared with 135 boe/d for the year ended December 31, 2009.

The average sales price on a boe basis was $31.43/boe in 2010, a 4.45% increase from the $30.09/boe received in 2009.

On a barrel of oil equivalent basis, during 2010 oil and NGL accounted for 17.54% of total sales and natural gas accounted for 82.46% of total sales, compared to 2009 when oil and NGL accounting for 19.26%, with natural gas accounted for 80.74% of total sales.

FINANCIAL 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.

Year ended December 31	2010 ($)	2009 ($)	Percent Change (%)
Petroleum and natural gas revenue	1,311,685	1,487,795	(11.84)
Royalties, petroleum and natural gas	243,103	216,462	12.31
Production expenses, petroleum and natural gas	610,736	945,678	(35.42)
Operating netback, petroleum and natural gas	457,846	325,655	40.59
Net loss	1,442,287	1,634,427	(11.76)
Net loss per share (basic and diluted)	0.03	0.05	(40.00)
Revenue per boe	31.43	30.09	4.45
Royalty per boe	5.82	4.38	32.88
Operating costs per boe	14.55	19.13	(23.94)
Operating netback per boe	11.06	6.58	68.09
Total assets	6,386,495	6,361,967	0.39
Total long-term liabilities	417,245	199,676	108.96

Petroleum and natural gas revenue declined 11.84% to $1,311,685 for the year ended December 31, 2010 from revenue of $1,487,795 during the year ended December 31, 2009. The reduction of 11.84% was due to certain wells being shut in and delays in bringing wells on line as the Company awaits a rebound in natural gas prices. Revenue on a boe basis increased by 4.45% to $31.43/boe from $30.09 during 2009.

Royalties increased by 12.31% to $243,103 from $216,462 in 2009. Royalty per boe for 2010 averaged $5.82/boe, which was a 32.88% increase from $4.38/boe during 2009.

Production expenses in the year ended December 31, 2010 decreased from 2009 to $610,736 compared to $945,678 respectively. The decrease was primarily due to a focus on minimizing costs as natural gas prices continued to be stagnant. Operating costs/boe decreased by 23.94% to $14.55/boe from $19.13/boe in 2009.

Operating netback from petroleum and natural gas sales increased by 40.59% to $457,846 during 2010 from $325,655 during 2009, mainly due to lower production volumes as certain wells were shut in as well as certain wells not being brought on line yet.

Operating netback/boe increased by 68.09% to $11.06/boe from $6.58/boe.

Royalties per unit of Production			
Year ended December 31	2010	2009	Percent Change %
Gas ($/mcf)	0.58	0.49	18.36
Oil ($/bbl)	5.21	3.71	40.43
NGL ($/bbl)	24.95	16.43	51.86
Total ($/boe)	5.82	4.38	32.88

The royalties per mcf for natural gas increased by 18.36% to $0.58/mcf from $0.49/mcf in 2009. Oil royalties increased by 40.43% to $5.21/bbl from $3.71/bbl in 2009. NGL royalties were 51.86% higher in 2010. Combined royalties for all products increased by 32.88% to $5.82/boe in 2010 from $4.38/boe the previous year.

GENERAL & ADMINISTRATIVE EXPENSES

After recoveries, general and administrative expenses ("G&A") decreased by 6.71% to $1,159,410 in 2010 from $1,242,824 in 2009. G&A expenses decreased throughout the year primarily due to the increased efficiencies within the Company.

GENERAL & ADMINISTRATIVE EXPENSES			
Year ended December 31	2010 ($)	2009 ($)	Percent Change (%)
Net G&A Expenses	1,159,410	1,242,824	(6.71)

STOCK BASED COMPENSATION

During the year ended December 31, 2010, the Company granted 3,450,000 stock options, 550,000 options expired unexercised, 690,000 stock options cancelled, 1,090,617 Agent Options expired unexercised, and there were no exercises. Compensation expense recognized year ended December 31, 2010 was $109,560 (December 31, 2009 - $nil) all of which has been recorded as a non-cash stock-based compensation expense. The total amount has been recorded as an offsetting credit to contributed surplus.

ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations increased by 34.16% from $131,757 during 2009 to $176,768 during 2010. The increase was primarily due to revisions in cost estimates recognized during 2010 as they related to liabilities that existed at December 31, 2009.

DEPLETION, DEPRECIATION & ACCRETION EXPENSES

Depletion and depreciation expense, an accounting measure of our finding and on-stream costs, is calculated using the ratio of capital costs to proven reserves. Capital costs include the net book value of historical costs incurred and estimated future expenditures to develop proved reserves less the estimated net realizable value of production equipment and facilities after proved reserves are fully developed.

Asset retirement obligation is the present value of management's estimate of future costs to be incurred to properly abandon and reclaim the properties held by the Company. Accretion expense is the increase in the asset retirement obligation resulting from the passage of time.

DEPLETION, DEPRECIATION & ACCRETION

Year ended December 31	2010 ($)	2009 ($)	Change Percent %
Depletion, depreciation and accretion	589,477	905,864	(34.93)
Asset retirement obligation at year end	176,768	131,757	34.16

During the year ended December 31, 2010, depletion, depreciation and accretion (DD&A) expenses were 34.93% lower at $589,477 compared to $905,864 during 2009. The decrease in DD&A was primarily due to an impairment of petroleum and natural gas assets recorded during 2009 of 289,171, which has been included in DD&A. There was no impairment recognized during 2010.

CASH FLOWS FROM OPERATIONS

During the year ended December 31, 2010, cash flows used in operations increased by 750.42% to $1,398,929 from $164,498 during 2009. This increase was primarily due to the working capital fluctuations.

Funds used in operations during the year ended December 31, 2010 decreased by 31.09% to $746,336 from the previous year's $1,083,013. The decrease in funds used in operations was predominately due to lower operating costs and general and administrative costs during 2010 as compared to 2009.

CAPITAL EXPENDITURES

CAPITAL EXPENDITURES

Year ended December 31	2010 ($)	2009 ($)	Percent Change (%)
Capital expenditures	680,762	1,262,675	(46.09)

The decrease of 46.09% in capital expenditures during 2010 as compared to 2009 was primarily due to lower natural gas prices delaying certain projects until there is a rebound in the commodity price.

QUARTERLY FINANCIAL INFORMATION

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

Quarterly Financial Information ($000 except per share and unit values)	**Dec 31** **2010**	**Sep 30** **2010**	**Jun 30** **2010**	**Mar 31** **2010**	**Dec 31** **2009**	**Sep 30** **2009**	**Jun 30** **2009**	**Mar 31** **2009**
Petroleum and natural gas sales	224	315	375	398	486	301	316	384
Net income	(618)	(375)	(325)	(124)	(1,005)	(281)	(450)	102
Net income per share Basic and diluted	(0.01)	(0.01)	(0.01)	(0.00)	(0.03)	(0.01)	(0.02)	0.01
Average daily sales								
Natural gas (mcf/d)	470	553	585	654	781	668	606	585
Oil/NGL (bbls/d)	22	17	23	19	19	29	26	27
Barrels of oil equivalent (boe/d)	100	109	121	128	149	140	128	124
Average sales prices								
Natural Gas ($/mcf)	2.15	4.59	4.51	4.77	4.36	2.59	4.17	5.68
Oil/NGL ($/bbl)	66.09	52.69	63.56	67.74	96.22	52.82	35.54	35.39
Barrels of oil equivalent ($/boe)	24.37	31.42	34.13	34.48	35.47	23.29	27.23	34.35
Operating costs ($/boe)	16.32	13.77	15.97	12.51	33.92	13.85	16.10	10.33
Royalty Expense ($/boe)	5.66	5.49	3.60	8.37	6.63	3.27	4.53	2.76
Operating netback ($/boe)	2.39	12.16	14.56	13.60	(5.08)	6.17	6.60	21.26

Explanation of Quarterly Variances

On a quarter by quarter basis production volumes trended up throughout 2009, but as prices continued to be significantly lower than forecasted throughout 2010 projects were delayed and certain wells were shut in until such time that commodity prices rebound. The net loss in the quarters is largely a result of these factors.

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 $2,875,000 (December 31, 2009 – $2,935,019), has been drawn at December 31, 2010. Interest on the Revolving Loan is calculated daily and payable monthly on the outstanding principal amount drawn at a rate per annum equal to the bank's prime rate plus 2.00% (December 31, 2009 – bank's prime rate plus 1.50%).

During the year ended December 31, 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 daily and payable monthly on the outstanding principal amount at a rate per annum equal to the bank's prime rate plus 2.50%. The full amount has been drawn as at December 31, 2010.

The Company is bound by certain debt covenants. These 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 A) to Current Liabilities (excluding any current portion of Bank Debt). As at December 31, 2010, the Company was in violation of this bank covenant with a ratio of 0.38:1. The bank has not made demand of the Company's credit facilities but retains the right to do so.

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 has received preliminary expressions of interest from third parties, interested in investing substantial sums in the Company if it focuses on its US properties. The Company's US prospect should produce better returns due to higher oil prices compared with natural gas, it has greater drilling potential and more locations. Given Emerald Bay's recurring operating losses it is critical that the Company refocus to an area with the potential of growth and positive cash flow and income that the U.S. has.

OUTSTANDING SHARE DATA

On March 4, 2010, the Company issued 5,000,000 common shares with a value of $400,000 ($.08/share). These shares were issued as consideration for the purchase of an interest in a private Texas based oil and gas company.

The Company completed a private placement ("Placement A"), issuing 8,850,000 units for total proceeds of $442,500, ($0.05 per unit). Each unit consists of one common share of the Company (issued either as a common share or as a flow-through share (the "FTS")) and one common share purchase warrant (the "Warrant A"). Each whole Warrant entitles the holder to purchase one additional common share of the Company at $0.12 per share, exercisable for 1 year from the date of Placement A. Of the total 8,850,000 units issued, 6,900,000 were issued as a FTS. The Company has allocated $5,863 of the unit value to warrants.

The Company completed a private placement ("Placement B"), issuing 4,300,000 units for total proceeds of $215,000, ($0.05 per unit). Each unit consists of one common share of the Company (issued either as a common share or as a FTS) and one Warrant A. Of the total 4,300,000 units issued, 1,300,000 were issued as a FTS. The Company has allocated $7,474 of the unit value to warrants.

Pursuant to Placement A and Placement B, the Company incurred $55,227 in cash share issue costs and issued 750,000 finders options (the "Finders Options") valued at $5,666.

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

	May 2, 2011	**December 31, 2010**
Common Shares	72,723,147	63,309,446
Warrants (i)	22,563,701	13,150,000
Stock Options (ii)	4,060,000	4,060,000

Notes:

i) 8,350,000 of the Warrants entitle the holder to acquire one additional common share for $0.12 per share until September 30, 2011. 500,000 of the Warrants entitle the holder to acquire one additional common share for $0.12 per share until October 27, 2011. 4,300,000 of the Warrants entitle the holder to acquire one additional common share for $0.12 per share until December 30, 2011. 7,503,701 of the Warrants entitle the holder to acquire one additional common share for $0.10 per share until September 29, 2012. 1,910,000 of the Warrants entitle the holder to acquire one additional common share for $0.10 per share until October 13, 2012.

ii) 1,000,000 of the Stock Options entitle the holders to acquire an equal number of common shares at $0.25 per share until January 13, 2011. 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. 2,760,000 of the Stock Options entitle the holders to acquire an equal number of common shares at $0.10 per share until April 6, 2015.

OFF BALANCE SHEET ARRANGEMENTS

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

RELATED PARTIES

The Company maintains a small staff and only has two individuals on payroll. The balance of the individuals (including two directors) who work for the Company do so on a non-exclusive basis as consultants. As a result much of the general and administrative spending of the Company is to a related party. 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.

a) The following amounts are due by related parties:

	2010	2009
	$	$
Note receivable from officer (i)	225,054	218,500
Fair value allowance (ii)	(206,710)	(206,710)
Net note receivable	18,344	11,790
Advance fees (iii)	33,029	51,448
	51,373	63,238

(i) A promissory note was issued to an officer of the Company 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 $19,650 at December 31, 2010 (December 31, 2009 - $35,370).

(ii) The fair value allowance was determined in 2008, based on the market value of the secured shares at December 31, 2008. The Company has not provided an additional allowance to the estimated fair value of the 393,000 common shares held as security as the fair value at December 31, 2010 and 2009 exceeded the carrying amount.

(iii) During the year ended December 31, 2008, a director was advanced $59,473 in relation to efforts to finance and advance the Company's drilling technology. At December 31, 2010 $33,029 (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. During the year ending December 31, 2010, the original repayment date of December 31, 2010 was extended to December 31, 2011.

b) Additional related party transactions are as follows:

(i) Aggregate fees of $85,000 (December 31, 2009 - $187,319) were charged by officers of the Company. Of this amount $24,100 (December 31, 2009 - $187,319) was recorded in the statement of operations, comprehensive loss and deficit and $60,900 (December 31, 2009 - $nil) was capitalized to property, plant and equipment.

(ii) Aggregate consulting fees of $256,500 (December 31, 2009 - $276,569) were charged by directors and officers of the Company and were expensed as general and administrative expenses.

(iii) Aggregate legal fees of $7,854 (December 31, 2009 - $33,200) 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.

(iv) Aggregate fees of $43,200 (December 31, 2009 - $77,000) 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 recorded in the statement of loss, comprehensive loss and deficit.

(v) Included in accounts payable at December 31, 2010 was $51,636 owing to related parties of the Company and $114,976 owing to the Company from related parties.

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.

COMMITMENTS

a) Under a lease agreement for five (5) years commencing April 1, 2009 and ending March 31, 2014, the Company has committed to payments of $5,420 per month under a rental agreement for office space.

b) The Company has entered into various vehicle loan agreements with estimated minimum annual payments of approximately $27,800 per year through 2015. Total annual principal repayments for fiscal years 2011 through to 2015 are respectively as follows: $22,075, $23,345, $24,688, $26,110 and $15,846.

c) As partial consideration for the non-controlling acquisition of the shares of a Texas oil and gas company, the Company has entered into a consulting contract aggregating $37,919 (USD -$36,800). The contract commences March 1, 2010 and has a term of 18 months.

d) The Company is committed to renounce to subscribers $410,000 of expenditures that qualify as CEE for Canadian income tax purposes and to incur these expenditures no later than December 31, 2011.

SUBSEQUENT EVENTS

Subsequent to December 31, 2010 the Company closed a private placement (the "Private Placement") pursuant to which 9,413,701 units (the "Units") were issued at a price of $0.05 per Unit, for aggregate proceeds of $470,685. Each Unit consisted of one common share of the Company, issued either as a common share or as a flow-through share at the scribers option) and one share purchase warrant (the "Warrant"). Each whole Warrant is exercisable for one additional common share of the Company for a period of 18 months from the issuance of the Units at a price of $0.10 per share. Of the total Units issued, an aggregate of 6,163,701 were issued as flow-through shares.

Cash proceeds of $3,500 and 70,000 finder's options (the "Finder's Options") were issued to those who facilitated the private placement. Each Finder's Option entitles the holder to acquire one Unit of the Company at a purchase price of $0.05 per Unit for a period of 12 months from the issuance of the Finder's Option.

RISK FACTORS AND RISK MANAGEMENT

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

Commodity Price Risk

Historically the Company has sold all of its product on the spot market. However, the Company was concerned about the near future value natural gas and therefore, in 2010, the Company was subject to a financial instrument collaring the received price of natural gas between $4.53/GJ and $7.53/GJ for 500 GJ/day. The company recorded a realized gain of $113,616 in 2010 in relation to this financial instrument. In 2011, the Company will be subject to an enhanced swap financial instrument whereby the Company will receive a swap price of $4.68/GJ for 500 GJ/day for $90 USD Call Options of WTI-NYMEX-OIL, 50bbl/day in 2011 and 30bbl/day in 2012.

Production Risk

The Company believes it has a stable production base from a variety of wells. However, the Company remains subject to the risk that a significant decrease in production from some wells could result in a material decrease in the Company's production and associated cash flow.

Reserve Replacement Risk

EBY's production is subject to natural declines and the Company plans to replace production with acquisitions and developing new reserves. To remain financially viable, the Company must be able to replace reserves at a lesser cost on a per unit basis than its cash flow on a per unit basis. The Company closely monitors the capital expenditures made for the purpose of increasing its petroleum and natural gas reserves.

Regulatory Risk

Government royalties, income tax laws, environmental laws and regulatory requirements can have a significant impact on EBY's finances and operations. EBY strives to remain knowledgeable regarding changes to the regulatory regime under which it operates. All EBY properties are currently located in Alberta. Sudden regulatory or royalty changes by future government action is unpredictable and cannot be forecast by the Company.

Climate Change Risk

North American climate change policy is evolving and changing at both regional and national levels. EBY expects that some of its operations may be subject to future regional, provincial and/or federal climate change regulations to manage greenhouse gas. The exact scope and timing of new climate change measures is difficult to predict.

FINANCIAL INSTRUMENTS

a) **Fair values**

At December 31, 2010, the Company's financial instruments consist of cash and cash equivalents, accounts receivable, the equity investment, the bank loan and accounts payable and accrued liabilities. The fair values of these financial instruments approximate their carrying value due to their short-term nature.

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 December 31, 2010, the Company's cash and cash equivalents and the equity investment have been assessed based on the fair value hierarchy above. Cash and cash equivalents and short-term investments are assessed through level 1, 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, and the concentration risk within the accounts receivable balance is minimal. The Company has experienced $5,917 in credit loss in the collection of accounts receivable in the year ended December 31, 2010 (December 31, 2009 - $nil).

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 the year ending December 31, 2010 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 instrument was classified as held-for-trading and the reported fair value changes during the year were recorded through the statement of loss, comprehensive loss, and deficit. The realized gain recorded by the Company on the derivative financial instrument for the year ended December 31, 2010 was $113,616.

On October 27, 2010, the Company entered into a derivative financial instrument, which becomes effective on January 1, 2011 to December 31, 2011 ("Option A"). This instrument fixes the received price of natural gas at CDN 4.684 per GJ. As at December 31, 2010, the Company has recorded an unrealized gain in the statement of operations, comprehensive loss and deficit of $162,458. The unrealized gain represents the market value of the contract as at December 31, 2010.

On October 28, 2010, the Company entered into two commodity call options. The first option ("Option B") is effective from January 1, 2011 to December 31, 2011 and the second option ("Option C") is effective from January 1, 2012 to December 31, 2012. Both Options have a strike price of USD $90.00 per BBL. As at December 31, 2010, the Company has recorded an unrealized loss in the statement of operations, comprehensive loss and deficit of $316,225. The unrealized loss represents the market value of the contract as at December 31, 2010.

The following table summarizes the fair value of the Options as at December 31, 2010:

	Short-term	Long-term
Option A	162,458	-
Option B	(165,736)	-
Option C	-	(150,488)
Financial contract, December 31, 2010	(3,278)	(150,488)

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 $103,100 increase or decrease in the Petroleum and Natural Gas sales for the year ended December 31, 2010.

Interest rate risk

The Company is exposed to interest rate risk on its revolving loan and non-revolving loan, which have interest rates of the bank's prime rate plus 2.00% and prime plus 2.50%, respectively. An estimated 1.00% increase or decrease in the interest rate would have affected the Company's statement of operations by $29,000 for year ended December 31, 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 December 31, 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 $5,170 impact on the Company’s earnings for the year.

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	$1,764,461	This amount is anticipated to be met out of additional share issuance in the 2011 fiscal period.
Bank loan	$3,275,000	The Company anticipates issuing additional share capital to reduce this amount in 2011. 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 year.
Long term debt	$89,989	Vehicle loans will be paid over 5 years out of normal cash flow.

SELECTED ANNUAL INFORMATION

	2010	2009	2008
Petroleum and natural gas sales	1,311,685	$1,487,795	$2,890,701
Net loss	1,442,287	1,634,427	722,275
Net loss per share			
Basic and Diluted	(0.03)	(0.05)	(0.05)
Funds (used in) from operating activities	(746,336)	(1,083,013)	170,117
Total assets	6,386,495	6,361,967	6,506,209
Current net debt	5,039,461	4,331,946	2,692,927

The most significant driver of this variation from 2008 forward is the commodity price. With commodity prices in 2009 and 2010 roughly half of what they were in 2008, revenues are down correspondingly and losses have increased. This has been reflected in increased net debt.

OUTLOOK

In addition to the current pipeline operations in Alberta, and based on the continuation of low natural gas prices, Emerald Bay has transitioned its development focus to oil development in both Texas and Alberta. The initial impact of this transition shows a lower production volume in our overall output. The daily production rates in our PRI affiliate is not reported in Emerald Bay's average daily production rate. These volumes will be periodically reported through press releases after we are confident we have completed our land acquisition efforts in the area.

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. We are confident that we have prepared ourselves to emerge from this environment operationally strong, and we expect to be well positioned to respond quickly when the business environment improves. Our proven management and dedicated team of professionals are engaged and committed to developing our high-quality asset base.

ADOPTION OF ACCOUNTING POLICIES

Investments

Investments in companies subject to significant influence are accounted for using the equity method. The equity method is a basis of accounting whereby the investment is initially recorded at cost and the carrying value is adjusted thereafter to include the Company's pro-rata share of post-acquisition income or loss. The amount of the adjustment is included in the determination of net (loss) income by the Company and the investment account of the Company is also increased or decreased to reflect the Company share of capital transactions and changes in accounting policies and corrections of errors. Profit distributions received or receivable from the investments will reduce the carrying value of the investment. Investments accounted for on the equity basis are written down to their fair value when they have a loss in value that is other than a temporary decline.

CRITICAL ACCOUNTING ESTIMATES

The amounts recorded for depletion and depreciation of property and equipment, the ceiling test calculations and evaluations of unproved properties are based on estimates of proven reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions.

The assumptions used in the determination of the fair value of stock options issued are based on estimates of the future volatility of the Company's stock price, expected lives of the options, expected dividends and other relevant assumptions.

Inherent in the fair value calculation of asset retirement obligations are numerous assumptions and judgments including estimates of the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal and regulatory environments. To the extent future revisions to these assumptions impact the fair value of the existing asset retirement obligation, a corresponding adjustment is made to the property and equipment balance.

The capital expenditures classifications are made based on estimates from geological and geophysical information obtained. The classification of the expenditures may be challenged by the taxation authorities and in this regard the assessments may be different from that of management.

The financial statements include accruals based on the terms of existing joint venture agreements. Due to varying interpretations of the definition of terms in these agreements the accruals made by management in this regard may be significantly different from those determined by the Company's joint venture partners.

By their nature, these estimates are subject to measurement uncertainty, and the effect of changes in such estimates on the financial statements of future periods could be significant.

FUTURE ACCOUNTING AND REPORTING CHANGES

International Financial Reporting Standards ("IFRS")

In February 2008, the CICA Accounting Standards Board ("AcSB") confirmed that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards "IFRS" for fiscal periods beginning on or after January 1, 2011. The adoption 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, including the opening balance sheet at January 1, 2010. The Company is progressing in its IFRS transition project in preparation for timely completed of the first IFRS interim financial report in the first quarter of 2011.

The IFRS conversion project to date has identified a number of differences between currently applied accounting policies and IFRS, based on the accounting standards and interpretations in effect as at December 31, 2010.
Based on the analysis to date, management believes that IFRS will not have a significant impact on the Company's existing business processes and its internal controls environment, but further analysis by the Company continues during the final phase of the project.

<u>Property and Equipment:</u>
In accordance with IFRS 1, at the date of transition to IFRS, the Company has elected to measure property, plant and equipment at deemed cost. As at the transition date, the Company reclassified $117,000 of exploration and evaluation assets from the full cost pool to intangible exploration assets at the amount that was recorded in Canadian GAAP.
Once the exploration and evaluation assets are reclassed, the remaining Canadian GAAP full cost pool was allocated to producing assets and components on a pro rata basis to the underlying assets using proved reserves values at the transition date.

Management has identified an approach to componentization and depletion. The Company will use the unit of production method basis based on proved reserves. Depletion will be prepared on a field level under IFRS versus a cost center under Canadian GAAP. The Company expects to increase depletion recorded for the year ended December 31, 2010.

Asset Impairments:
Under CGAAP, impairment of oil and gas properties is estimated based on undiscounted future cash flows compared to the asset's carrying amount and if impairment is indicated, discounted cash flows are prepared to quantify the amount of the impairment.

Under IFRS, the Company prepared discounted cash flows to determine the recoverable amount at a cash generate unit level. Management has identified cash-generating units and an approach for assessing the fair value less cost to sell of assets. With the adoption of IAS 36, the Company does not expect an impairment to be recognized update IFRS transition date of January 1, 2010.

Decommissioning Liabilities:
Since the Company has elected to apply the IFRS 1 full-cost as deemed cost exemption, decommissioning liabilities must be measured as at January 1, 2010 in accordance with IAS 37. The difference between that amount and the carrying amount of those liabilities at the date of transition is recognised directly in retained earnings. At the transition date, the Company expects to increase the amount of the decommissioning liability due to a reduction in the discount rate. Future impacts are anticipated to impact decommissioning liabilities, accretion expense, future (deferred) and current income taxes.

Share Based Payments:
Under previous GAAP the Company's equity-settled share-based payments were measured at their fair value at the grant date. This amount was expensed to stock compensation on the income statement on a straight-line basis or graded basis over the vesting period. Forfeitures were accounted for as they occurred. Under IFRS, an estimate of forfeitures must be factored into the calculation of the expense at the grant date and any difference between the estimates and actual is recognized in the period when actual forfeitures are incurred. The Company expects a reduction to stock based compensation expense for the year-end December 31, 2010.

Income Taxes:
Both Canadian GAAP and IFRS follow the liability method of accounting for income taxes, where tax liabilities and assets are recognized on temporary differences. The Company's future (deferred) income tax asset/liability will be impacted by the tax effects resulting from the IFRS changes discussed above.

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. The Company is assessing the impact of these new standards.