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") unaudited interim financial statements for the three and nine months ended September 30, 2012. 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 MD&A is dated November 29, 2012.

BASIS OF PRESENTATION

The financial data presented below has been prepared in accordance with International Financial Reporting Standards.

Accounting Policies and Application of Accounting Estimates

The significant accounting policies used by EBY are disclosed in Note 3 of the audited annual 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-IFRS Measures

This MD&A includes the following measures that are from time to time used by the Company, but do not have any standardized meaning under IFRS or GAAP and may not be comparable to similar measures presented by other companies:

a) "Funds from operations" - should not be considered an alternative to, or more meaningful than "cash flow from operating activities" as determined in accordance with IFRS 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 decommissioning liability 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.

b) "Operating netback" - Operating netbacks are calculated by deducting royalties and operating costs, including transportation costs, from revenues.

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

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

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 may contain 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 forward looking statements contained herein 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 MD&A, 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.

SELECTED QUARTERLY AND YEAR TO DATE FINANCIAL INFORMATION

	Three months ended September 30			Nine months ended September 30		
	2012	**2011**	**Change %**	**2012**	**2011**	**Change %**
FINANCIAL ($)						
Gross revenue	46,472	260,477	(82.16)	134,928	869,917	(84.49)
Total assets	2,196,539	4,585,858	(52.10)	2,196,539	4,585,858	(52.10)
Cash flow used in operations	371,178	309,095	20.09	1,161,308	794,375	46.19
Per share – basic and diluted	(0.00)	(0.00)	-	(0.01)	(0.01)	-
Net comprehensive (loss) income	(304,504)	150,353	(302.53)	(1,216,318)	(453,075)	168.46
Per share – basic and diluted	(0.00)	0.00	-	(0.01)	(0.01)	-
Capital expenditures	1,079	1,964	(45.06)	25,833	77,996	(66.88)
Exploration and evaluation expenditures	193,996	-	-	193,996	-	-
Bank loan	-	2,675,000	-	-	2,675,000	-
OPERATIONS						
Average Production sales						
Oil (bbl/d)	6	6	-	4	7	(42.86)
Natural gas (mcf/d)	16	401	(96.01)	37	443	(91.65)
NGL (bbl/d)	-	13	-	-	12	-
Total (boe/d @ 6 mcf: 1 bbl)	8	85	(90.59)	11	92	(88.04)
Average pricing						
Natural gas ($/mcf)	1.59	3.84	(58.59)	2.39	3.94	(39.34)
Oil ($/bbl)	85.72	82.49	3.92	87.74	90.96	(3.54)
NGL ($/boe)	83.75	64.06	30.74	70.97	69.53	2.07
Combined ($/boe)	61.16	33.20	84.22	45.44	34.48	31.79
Expenses						
Production expense & transportation ($/boe)	51.58	18.01	186.40	53.09	19.26	175.65
Royalty expense ($/boe)	1.16	5.76	(79.86)	(1.93)	4.44	(143.47)
Net Back Combined ($/boe)	8.42	9.43	(10.71)	(5.72)	10.78	(153.06)

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.

Prior to December 31, 2011, management was committed to selling certain oil and gas assets and was actively marketing and accepting purchase proposals. Effective January 1, 2012, the Company disposed of its primary Canadian producing oil and gas assets, and discontinued recording the revenue, operating expenses and royalties related to the assets on the effective date of the sale. The disposition of the assets was closed on March 16, 2012 for gross proceeds of $1,500,000, with no gain or loss recognized on the sale. The full amount of the proceeds were used to repay the Revolving Loan. The sale of these assets resulted in a significant decline of revenue, royalties and operating expenses during the three and nine months ended September 30, 2012 compared to the same period in 2011.

Petroleum and natural gas revenue was $46,472 and $134,928 for the three and nine months ended September 30, 2012, respectively, from revenue of $260,477 and $869,917 during the three and nine months ended September 30, 2011, respectively. The fluctuations year over year are due to the sale of certain Canadian oil and gas assets during 2012, and during the fourth quarter of December 31, 2011, including the Company's primary revenue generating property. Additionally, due to the continued decline in natural gas prices, the Company's remaining assets continued to be shut in to preserve reserves until prices rebound. These factors, combined with increased general and administrative costs to retire the Company's bank debt caused a higher net loss for the three and nine months ended September 30, 2012 compared to 2011.

Natural gas prices decreased to $1.59/mcf and $2.39/mcf in the three and nine months ended September 30, 2012, respectively, versus $3.84/mcf and $3.94/mcf in the three and nine months ended September 30, 2011, respectively. Oil prices increased to $85.72 in the three months ended September 30, 2012 from $82.49 in the three months ended September 30, 2011 and decreased to $87.74 in the nine months ended September 30, 2012 from $90.96 in the nine months ended September 30, 2011. Liquid prices increased to $83.75 in the three months ended September 30, 2012 from $64.06 in the three months ended September 30, 2011 and increased to $70.97 in the nine months ended September 30, 2012 from $69.53 in the nine months ended September 30, 2011. The average sales price on a boe basis was $61.16 and $45.44 in the three and nine months ended September 30, 2012, respectively, compared to $33.20 and $34.48 in the three and nine months ended September 30, 2011.

During the three and nine months ended September 30, 2012, the average sales volume on a boe/d basis decreased to 8 boe/d and 11 boe/d, respectively, compared with 85 boe/d and 92 boe/d for the three and nine months ended September 30, 2011.

During the nine months ended September 30, 2012, cash flows used in operations increased to $1,161,308 from $797,375 in the nine months ended September 30, 2011.

OPERATING RESULTS

Sales	Average Daily Volumes			Average Prices		
9 months ended	September 30, 2012	September 30, 2011	Percent Change %	September 30, 2012	September 30, 2011	Percent Change %
Natural gas (mcf)	37	443	(91.65)	2.39	3.94	(39.34)
Oil (bbls)	4	7	(42.86)	87.74	90.96	(3.54)
NGL (bbls)	-	12	-	70.97	69.53	2.07
Barrels of oil equivalent (boe)	11	92	(88.04)	45.44	34.48	31.79

For the period ended September 30, 2012 natural gas sales decreased 37 mcf/d from 443 mcf/d the previous year. Oil production for the period ended September 30, 2012 decreased to 4 bbls/d compared to 7 bbls/d for the period ended September 30, 2011. During the period ended September 30, 2012 liquid sales decreased 0 bbl/d from 12 bbl/d the previous year. During the period ended September 30, 2012, the average sales volume on a boe/d basis decreased to 11 boe/d compared with 92 boe/d for the period ended September 30, 2011. These decreases were primarily due to sale of the Company's primary Canadian oil and natural gas asset and additionally as certain wells were shut in due to the lower natural gas prices.

Natural gas prices decreased to an average of $2.39/mcf during the period ended September 30, 2012 versus $3.94/mcf during the same period in 2011. The average NGL price increased to $70.97/bbl compared to $69.53/bbl received in 2011. During the period ended September 30, 2012, the average price received for oil was $87.74/barrel versus $90.96/barrel during the previous year. Most of EBY's production is medium viscosity crude which receives higher pricing.

The average sales price on a boe basis was $45.44/boe in 2012 compared to $34.48/boe received in 2011.

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.

Nine months ended September 30,	2012 ($)	2011 ($)	Percent Change (%)
Petroleum and natural gas revenue	134,928	869,917	(84.49)
Royalties, petroleum and natural gas	5,724	(112,115)	(105.11)
Production expenses, petroleum and natural gas	(157,645)	(485,926)	67.56
Operating netback, petroleum and natural gas	(16,993)	271,876	(106.25)
Net loss	(1,216,318)	(453,075)	168.46
Net loss per share (basic and diluted)	(0.01)	(0.01)	-
Revenue per boe	45.44	34.48	31.79
Royalty per boe	(1.93)	4.44	(143.47)
Operating costs per boe	53.09	19.26	175.65
Operating netback per boe	(5.72)	10.78	(153.06)

Petroleum and natural gas revenue decreased to $134,928 for the nine months ended September 30, 2012 from revenue of $869,917 during the nine months ended September 30, 2011. The decrease in revenue was due to the sale of the Company's primary Canadian oil and natural gas asset. The Company recorded a recovery in royalties after receiving an adjustment from the government. Revenue on a boe basis increased to $45.44/boe from $34.48 during the nine months ended September 30, 2011.

Royalties decreased by to a recovery of $5,724 from $112,115 during the nine months ended September 30, 2012 compared to the same period in 2011. The decrease in royalties was due to the sale of the Company's primary Canadian oil and natural gas asset combined with the recovery of royalties resulting from the adjustment received from the government. Royalty per boe for the nine months ended September 30, 2012 averaged ($1.93)/boe, a decrease from $4.44/boe during the nine months ended September 30, 2011.

Production expenses in the nine months ended September 30, 2012 decreased to $157,645 from the nine months ended September 30, 2011 of $485,926. The decrease was primarily due to the sale of certain oil and gas assets during the nine months ended September 30, 2012. Operating costs/boe for the nine months ended September 30, 2012 increased to $53.09/boe from $19.26/boe in the nine months ended September 30, 2011.

Operating netback from petroleum and natural gas sales decreased to ($16,933) during the nine months ended September 30, 2012 from $271,876 during the nine months ended September 30, 2011. This decrease was mainly due to the sale of certain Canadian oil and gas assets.

Royalties per unit of Production			
Nine months ended September 30,	2012	2011	Percent Change %
Gas ($/mcf)	(2.66)	0.12	(2,316.67)
Oil ($/bbl)	9.97	4.20	137.38
NGL ($/bbl)	75.44	28.42	165.45
Total ($/boe)	(1.93)	4.44	(143.47)

The royalties per mcf for natural gas decreased to $(2.66)/mcf from $.12/mcf in 2011. Oil royalties increased to $9.97/bbl from $4.20/bbl in 2011. NGL royalties increased to $75.44/bbl from $28.42/bbl in 2011. Combined royalties for all products decreased to $(1.93)/boe in 2012 from $4.44/boe the previous year.

GENERAL & ADMINISTRATIVE EXPENSES

After recoveries, general and administrative expenses (“G&A”) increased to $281,908 and $889,502 during the three and nine months ended September 30, 2012 from $270,879 and $858,354 for the same period during 2011. The slight increase is primarily due to the professional fees incurred to retire the bank debt, which amount to approximately $120,000, combined with the Company’s continued efforts to maintain efficiencies in all other G&A costs.

GENERAL & ADMINISTRATIVE EXPENSES						
	Three months ended September 30			**Nine months ended September 30**		
	2012 ($)	2011 ($)	Percent Change (%)	2012 ($)	2011 ($)	Percent Change (%)
Net G&A expenses	281,908	270,879	4.07	889,502	858,354	3.63

DECOMMISSIONING LIABILITIES

Decommissioning liabilities are 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 decommissioning liability resulting from the passage of time. Decommissioning liabilities decreased from $201,664 as at December 31, 2011 to $198,730 as at September 30, 2012. The decrease was primarily due to the disposal of certain Canadian oil and gas interests during the period ended September 30, 2012 that existed as at December 31, 2011.

DEPLETION & DEPRECIATION

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.

DEPLETION, DEPRECIATION & AMORTIZATION

	Three months ended September 30			**Nine months ended September 30**		
	2012 ($)	2011 ($)	Percent Change (%)	2012 ($)	2011 ($)	Percent Change (%)
Depletion, depreciation and amortization	23,555	97,924	(75.95)	84,476	301,324	(71.97)

During the three and nine months ended September 30, 2012, depletion and depreciation expenses were lower at $23,555 and $97,924 compared to $84,476 and $301,324 during the same period in 2011. The decrease was primarily due to the lower production volumes during 2012 compared to 2011 due lower commodity prices, and the disposal of certain oil and gas assets that existed during the same period in 2011.

CASH FLOWS FROM OPERATIONS

During the nine months ended September 30, 2012, cash flows used in operations increased to $1,161,308 from $794,375 at September 30, 2011. This increase was primarily due to lower sales revenue during 2012 and working capital fluctuations.

Funds used in operations during the nine months ended September 30, 2012 increased to $1,139,966 from the previous year's $581,802. The increase in funds used in operations was predominately due to lower revenues and higher proportionate general and administrative costs and operating costs during 2012 as compared to 2011.

CAPITAL EXPENDITURES

CAPITAL EXPENDITURES

Nine months ended September 30,	2012 ($)	2011 ($)	Percent Change (%)
Capital expenditures	25,833	77,996	(66.88)
Exploration and evaluation assets	193,996	-	-

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 ($000 except per share and unit values)	**Sep 30 2012**	**Jun 30 2012**	**Mar 31 2012**	**Dec 31 2011**	**Sep 30 2011**	**Jun 30 2011**	**Mar 31 2011**	**Dec 31 2010**
Petroleum and natural gas sales	46	27	62	213	260	349	260	200
Net income (loss)	(305)	(641)	(270)	(1,524)	150	(150)	(555)	(1,668)
Net loss per share								
Basic and diluted	(0.00)	(0.01)	(0.00)	(0.03)	0.00	(0.00)	(0.01)	(0.04)
Average daily sales								
Natural gas (mcf/d)	16	14	81	296	401	501	423	470
Oil/NGL (bbls/d)	6	4	4	17	18	22	15	22
Barrels of oil equivalent (boe/d)	8	7	18	66	85	105	86	100
Average sales prices								
Natural Gas ($/mcf)	1.59	1.68	2.68	3.35	3.84	4.03	3.93	2.15
Oil/NGL ($/bbl)	85.70	60.55	110.31	77.19	69.86	83.45	78.91	66.09
Barrels of oil equivalent ($/boe)	61.16	43.19	38.49	34.79	33.20	36.47	33.33	24.37
Operating costs ($/boe)	51.58	116.72	29.06	17.93	18.01	20.52	18.97	16.32
Royalty Expense ($/boe)	1.16	(19.84)	3.47	5.44	5.76	3.42	4.38	5.66
Operating netback ($/boe)	8.42	(53.69)	5.95	11.41	9.43	12.53	9.98	2.39

Explanation of Quarterly Variances

On a quarter by quarter basis production volumes continue to trend downward as prices continue to be significantly lower on a quarter by quarter basis for natural gas prices. In addition, during the three months ended March 31, 2012, the Company sold its primary revenue producing property causing a significant decline in volumes and revenue. Throughout 2010 and 2011 projects were delayed and certain wells were shut in until such time that commodity prices begin to increase. The net loss in the quarters is largely a result of these factors. During the nine months ended September 30, 2012, the Company sold its primary Canadian oil and natural gas.

Net comprehensive loss increased during the fourth quarter for both the year ended December 31, 2011 and December 31, 2010, primarily due to the impairment of property and equipment taken during both years, and during the year ended December 31, 2011, the impairments taken on the exploration and evaluation assets and the assets held for sale.

The impairments have all been recognized in the fourth quarter.

LIQUIDITY & CAPITAL RESOURCES

On June 23, 2011, the Company amended its revolving operating demand loan (the "Revolving Loan") with a Chartered Canadian Bank (the "Lender"). Pursuant to the amendment, the maximum amount available under the Revolving Loan was reduced from $3,000,000 to $1,575,000. The per annum interest rate was increased from the Lender's prime rate plus 2.00% to the Lender's prime rate plus 3.00%. Interest continued to be calculated daily and payable monthly on the outstanding principal amount drawn. At December 31, 2011, the Company had drawn $1,550,000 of the Revolving Loan. During the nine months ended September 30, 2012, the Company entered into an additional amending agreement whereby the Company was to reduce the Revolving Loan by $1,500,000 through the sale of certain oil and gas assets, which the Company fulfilled, and accordingly repaid the Revolving Loan in its entirety. An amending fee of $10,000 was paid to the Lender, and additionally, a $50,000 payable for the previous amendment was also paid to the Lender.

On August 15, 2011, the Company amended its existing non-revolving demand loan (the "Non-revolving Loan") to a maximum amount of $1,775,000. 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 5.00%. During the nine months ended September 30, 2012, the Company repaid the Non-revolving loan in its entirety through the acquisition of a shareholder loan. The Company incurred professional fees of approximately $120,000 to payout the Non-revolving Loan.

During the nine months ended September 30, 2012, the Company entered into a loan agreement (the "Loan Agreement") with a shareholder (the "Lender") whereby the Company received a $1,500,000 loan. Interest on the shareholder loan is 10% per annum, payable monthly, on the outstanding principal amount and compounds monthly. Pursuant to the Loan Agreement, the Company was required to make a principal repayment in the amount of $500,000 on or before August 15, 2012 with the remaining loan due on the maturity date of August 15, 2013. The Loan Agreement was amended whereby the required principal repayment of $500,000 due on August 15, 2012 was reduced to $300,000 due on November 30, 2012. The Company may, at any time, repay the loan in full without notice or penalty. If the Company is in default of the requirements included in the Loan Agreement or the Lender believes the Company's ability to repay the loan is impaired, the Lender may demand repayment of the loan or accelerate the date for payment. As at September 30, 2012, the Company had accrued $50,000 in interest.

OUTSTANDING SHARE DATA

On February 17, 2012, the Company completed a private placement, issuing 14,240,000 units. Each unit was issued at $0.05 for total proceeds of $712,000. Each unit consists of one common share of the Company and one share purchase warrant. Each warrant entitles the holder to purchase one additional common share of the Company at $0.10 per share, exercisable for 1 year from the original issue date. The Company has allocated $346,581 of the unit value to warrants. The Company incurred $36,200 in cash share issue costs and issued broker warrants valued at $20,272 to those who assisted in the private placement.

On July 5, 2012, the Company completed a private placement issuing 4,841,730 units. Each unit was issued at $0.07 for total proceeds of $338,921. Each unit consists of one common share of the Company and one share purchase warrant. Each warrant entitles the holder to purchase one additional common share of the Company at $0.10 per share, exercisable for 1 year from the original issue date. The Company has allocated $187,838 of the unit value to warrants. The Company incurred $6,000 in cash share issue costs.

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

	November 29, 2012	**September 30, 2012**
Common Shares	132,721,689	103,041,689
Warrants (i)	65,905,730	36,225,730
Stock Options (ii)	7,380,000	7,380,000

Notes:

i) 1,910,000 of the Warrants entitle the holder to acquire one additional common share for $0.10 per share until October 13, 2012. 4,000,000 of the Warrants entitle the holder to acquire one additional common share for $0.10 per share until December 13, 2012. 4,600,000 of the Warrants entitle the holder to acquire one additional common share for $0.10 per share until February 25, 2013. 1,634,000 of the Warrants entitle the holder to acquire one additional common share for $0.10 per share until April 11, 2013. 14,240,000 of the Warrants entitle the holder to acquire one additional common share for $0.10 per share until February 17, 2013. 5,000,000 of the Warrants entitle the holder to acquire one additional common share for $0.10 per share until August 15, 2013. 4,841,730 of the Warrants entitle the holder to acquire one additional common share for $0.10 per share until July 5, 2013. 29,680,000 of the Warrants entitle the holder to acquire one additional common share for $0.10 per share until October 25, 2013.

ii) 2,455,000 of the Stock Options entitle the holders to acquire an equal number of common shares at $0.10 per share until April 6, 2015. 4,925,000 of the Stock Options entitle the holders to acquire an equal number of common shares at $0.10 per share until August 25, 2016.

OFF BALANCE SHEET ARRANGEMENTS

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

RELATED PARTIES

Related party transactions not disclosed elsewhere in these financial statements are as follows:

a) The following amounts are due from related parties:

	September 30, 2012 $	December 31, 2011 $
Note receivable from officer (i)	**236,530**	231,609
Fair value allowance (ii)	**(216,515)**	(216,515)
Net note receivable	**20,015**	15,094
Advance fees (iii)	**6,529**	9,529
	26,544	24,623

(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 $23,580 at September 30, 2012 (December 31, 2011 - $15,094).

(ii) The fair value allowance was initially determined on December 31, 2008 based on the market value of the secured shares. During the three and nine months ended September 30, 2012, the Company did not provide an additional allowance to the estimated fair value of the 393,000 common shares held as security as the fair value was in excess of the carrying value (December 31, 2011 – allowance of $9,805).

(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 September 30, 2012 $6,529 (December 31, 2011 - $9,529) 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. The original repayment date of December 31, 2010 has been extended to December 31, 2012.

b) Additional related party transactions not disclosed elsewhere in these financial statements are as follows:

For the three months ended September 30:

(i) Aggregate fees of $40,000 (September 30, 2011 - $nil) were charged by directors and of the Company and was recorded in the statement of comprehensive loss.

(ii) Aggregate fees of $9,600 (September 30, 2011 - $17,800) 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. The total amount $9,600 (September 30, 2011 - $17,800) was recorded in the statement of comprehensive loss.

For the nine months ended September 30:

(iii) Aggregate fees of $47,500 (September 30, 2011 - $32,500) were charged by directors of the Company and was recorded in the statement of comprehensive loss.

(iv) Aggregate fees of $29,400 (September 30, 2011 - $60,275) 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. Of this amount $29,400 (September 30, 2011 - $41,725) was recorded in the statement of comprehensive loss and $nil (September 30, 2011 - $18,550) was capitalized to property and equipment.

(v) Included in accounts payable at September 30, 2012 was $153,213 owing to related parties of the Company (December 31, 2011 - $37,410).

Key management compensation

	September 30, 2012	December 31, 2011
	$	$
Compensation	**284,213**	362,912
Share based payments	**-**	60,393
Total	**284,213**	423,305

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 ending March 31, 2014, the Company has committed to payments of $2,771 per month for the lease of its 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 2012 through to 2015 are respectively as follows: $23,345, $24,688, $26,110 and $15,846.

c) The Company is committed to renounce to subscribers $321,998 and $360,185 of expenditures that qualify as cumulative exploration expenditures ("CEE") for Canadian income tax purposes and to incur these expenditures no later than December 31, 2011 and December 31, 2012, respectively. At September 30, 2012, the Company has incurred approximately $88,002 (December 31, 2011 - $88,002) as eligible flow through expenditures against the December 31, 2011 commitment.

RISK FACTORS AND RISK MANAGEMENT

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

Commodity Price Risk

During 2010, the Company entered into a commodity call option effective from January 1, 2012 to December 31, 2012 at a strike price of USD $90.00 per BBL. During the nine months ended September 30, 2012, the Company terminated the commodity call option for consideration of $116,114 and recognized an unrealized gain of $161,770 (September 30, 2011 – 158,707 and $120,675, respectively) to reverse the financial contract liability recorded at December 31, 2011.

Production Risk

The Company believes it will have the ability to have a stable production base from a variety of wells in the near future. 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.

SUBSEQUENT EVENTS

Subsequent to September 30, 2012, the Company closed a private placement through the issuance of 29,680,000 units (the "Units") for gross proceeds of $1,484,000 ($0.05/Unit). Each Unit consisted of one common share of the Company and one common share purchase warrant (the "Warrant"). Each full Warrant entitles the holder to purchase one additional common share of the Company for $0.10/common share for a period of 12 months from the issuance of the Units. The Company incurred cash share issue costs of $123,150 and issued an aggregate of 2,463,000 finder's options to those who facilitated the private placement. Each finder's option is exercisable into one Unit of the Company on the same terms and conditions as those received by the subscribers under the private placement.

OUTLOOK

Based on the continuation of low natural gas prices, the Company 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, but the increases in Oil output are starting to show. The daily production rates in the Company's PRI affiliate is not reported in the Company'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.

The Company 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.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Specific amounts and disclosures affected by estimates and assumptions are:

Reserves

Amounts recorded for depreciation, depletion and amortization and amounts used for impairment calculations are based on estimates of oil and natural gas reserves. By their nature, the estimates of reserves, including the estimates of future prices, costs, discount rates and the related future cash flows are subject to measurement uncertainty.

Determination of cash-generating units ("CGU")

Property and equipment are aggregated into CGUs based on their ability to generate largely independent cash flows and are used for impairment testing. The determination of the Company's CGUs is subject to management's judgment.

Decommissioning liabilities

The Company estimates the decommissioning obligations for oil and natural gas wells and their associated production facilities and pipelines. In most instances, removal of assets and remediation occurs many years into the future. Amounts recorded for the decommissioning obligations and related accretion expense require judgmental assumptions regarding removal date, future environmental legislation, the extent of reclamation activities required, the engineering methodology for estimating costs, future removal technologies in determining the removal costs, and liability specific discount rates to determine the present value of these cash flows.

Exploration and evaluation assets

The accounting policy for exploration and evaluation assets is described in note 3. The application of this policy requires management to make certain estimates and assumptions as to future events and circumstances as to whether economic quantities of reserves have been found.

Share-based compensation

Compensation costs accrued for share-based compensation plans are subject to the estimation of what the ultimate payout will be using pricing models such as the Black-Scholes model which is based on significant assumptions such as the future volatility of the market price of the Company's shares, the forfeiture rate, the interest rate and the expected term of the issued stock option.

Deferred taxes

The provision for income taxes is based on judgments in applying income tax law and estimates on the timing, likelihood and reversal of temporary differences between accounting and tax bases of assets and liabilities.

FUTURE ACCOUNTING AND REPORTING CHANGES

The Company has reviewed the new and revised accounting pronouncements that have been issued but are not yet effective and determined that the following may have an impact on the Company and will become effective beginning on or after January 1, 2013:

IFRS 9 – "Financial Instruments", which is the result of the first phase of the IASB's project to replace IAS 39 – "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. The adoption of this standard should not have a material impact on the Company's financial statements.

IFRS 10 – "Consolidated Financial Statements", which builds on existing principles and standards and identifies the concept of control as the determining factor in whether an entity should be included within the consolidated financial statements of the parent company.

IFRS 11 – "Joint Arrangements", which establishes the principles for financial reporting by entities when they have an interest in arrangements that are jointly controlled.

IFRS 12 – "Disclosure of Interest in Other Entities", which provides the disclosure requirements for interests held in other entitles including joint arrangements, associates, special purpose entities and other off balance sheet entities.

IFRS 13 – "Fair Value Measurement", which defines fair value, requires disclosure about fair value measurements and provides a framework for measuring fair value when it is required or permitted within the IFRS standards.

IAS 27 – "Separate Financial Statements", which provides amendments to IAS 27 to coincide with the changes made in IFRS 10, but retains the current guidance for separate financial statements.

IAS 28 – "Investments in Associate and Joint Ventures", which revised the existing standard and prescribes the accounting for investments and sets out the requirements for the application of the equity method when accounting for investments in associates and joint ventures.

IFRS 7 – "Financial Instruments: Disclosures" and IAS 32 "Financial Instruments: Presentation", provides amendments to the previously issued IFRS 7 "Financial Instruments: Disclosures" and IAS 32 "Instruments: Presentation", to provide clarity over the current offsetting model and develop common disclosure requirements to enhance the understanding of the potential effects of offsetting arrangements. Amendments to IFRS 7 are effective on January 1, 2013 with required retrospective application and early adoption permitted. Amendments to IAS 32 are effective on January 1, 2014 with required retrospective application and early adoption permitted.

IAS 1 – "Presentations of Items of OCI: Amendments to IAS 1 Presentation of Financial Statements", which provides stipulates for the amendment of the presentation of net earnings and OCI and also requires that items are grouped within OCI based on whether the items may be subsequently reclassified to profit or loss. Amendments to IAS 1 are effective for the Company beginning on January 1, 2012 with retrospective application and early adoption permitted.