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 six months ended June 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 August 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 June 30			Six months ended June 30		
	2012	**2011**	**Change %**	**2012**	**2011**	**Change %**
FINANCIAL ($)						
Gross revenue	26,527	349,486	(92.41)	88,456	609,440	(85.49)
Total assets	2,034,695	5,119,381	(60.26)	2,034,695	5,119,381	(60.26)
Cash flow used in operations	231,558	165,700	39.75	790,130	485,280	62.82
Per share – basic and diluted	(0.00)	(0.00)	-	(0.01)	(0.01)	-
Net comprehensive loss	641,422	47,431	1,252.33	911,814	603,428	51.11
Per share – basic and diluted	(0.01)	(0.00)	(100)	(0.01)	(0.01)	-
Capital expenditures	142,763	80,697	76.91	244,786	76,032	221.95
Bank loan	-	3,225,000	(100)	-	3,225,000	(100)
OPERATIONS						
Average Production sales						
Oil (bbl/d)	3	10	(70.0)	4	8	(50.00)
Natural gas (mcf/d)	14	501	(97.21)	47	465	(89.89)
NGL (bbl/d)	1	12	(91.67)	1	11	(90.90)
Total (boe/d @ 6 mcf: 1 bbl)	7	105	(93.33)	12	96	(87.50)
Average pricing						
Natural gas ($/mcf)	1.68	4.03	(58.31)	2.53	3.98	(36.43)
Oil ($/bbl)	87.92	93.83	(6.30)	89.33	94.22	(5.19)
NGL ($/boe)	(0.33)	74.62	(100.44)	63.34	72.75	(12.93)
Combined ($/boe)	43.19	36.47	18.43	39.78	35.06	13.46
Expenses						
Production expense & transportation ($/boe)	116.72	20.52	468.81	53.28	19.83	168.68
Royalty expense ($/boe)	(19.84)	3.42	(680.12)	(2.97)	3.85	(177.14)
Net Back Combined ($/boe)	(53.69)	12.53	(528.49)	(10.52)	11.39	(192.36)

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 six months ended June 30, 2012 compared to the same period in 2011.

Petroleum and natural gas revenue was $26,527 and $88,456 for the three and six months ended June 30, 2012, respectively, from revenue of $349,486 and $609,440 during the three and six months ended June 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 six months ended June 30, 2012 compared to 2011.

Natural gas prices decreased to $1.68/mcf and $2.53/mcf in the three and six months ended June 30, 2012, respectively, versus $4.03/mcf and $3.98/mcf in the three and six months ended June 30, 2011, respectively. Oil and NGL combined prices decreased to $60.55 in the three months ended June 30, 2012 from $83.45 in the three months ended June 30, 2011 and increased to $84.80 in the six months ended June 30, 2012 from $81.59 in the six months ended June 30, 2011. The average sales price on a boe basis was $43.19 and $39.78 in the three and six months ended June 30, 2012, respectively, compared to $36.47 and $35.06 in the three and six months ended June 30, 2011.

During the three and six months ended June 30, 2012, the average sales volume on a boe/d basis decreased to 7 boe/d and 12 boe/d, respectively, compared with 105 boe/d and 96 boe/d for the three and six months ended June 30, 2011.

During the six months ended June 30, 2012, cash flows used in operations increased to $790,130 from $485,280 in the six months ended June 30, 2011.

OPERATING RESULTS

SALES ***6 months ended***	Average Daily Volumes			Average Prices		
	June 30, 2012	June 30, 2011	Percent Change %	June 30, 2012	June 30, 2011	Percent Change %
Natural Gas (mcf)	47	465	(89.89)	2.53	3.98	(36.43)
Oil (bbls)	4	8	(50.00)	89.33	94.22	(5.19)
NGL (bbls)	1	11	(90.91)	63.34	72.75	(12.93)
Barrels of Oil Equivalent (boe)	12	96	(87.50)	39.78	35.06	13.46

For the period ended June 30, 2012 natural gas sales decreased by 89.89%, to 47 mcf/d from 465 mcf/d the previous year. Oil production for the period ended June 30, 2012 decreased to 4 bbls/d compared to 8 bbls/d for the period ended June 30, 2011. During the period ended June 30, 2012 liquid sales decreased by 90.90%, to 1bbl/d from 11 bbl/d the previous year. During the period ended June 30, 2012, the average sales volume on a boe/d basis decreased by 87.5% to 12 boe/d compared with 96 boe/d for the period ended June 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 an average of 36.43% during the period ended June 30, 2012 to $2.53/mcf versus $3.98/mcf during the same period in 2011. The average NGL price decreased 12.93% to $63.34/bbl compared to $72.75/bbl received in 2011. During the period ended June 30, 2012, the average price received for oil was $89.33/barrel versus $94.22/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 $39.78/boe in 2012, an 13.46% increase from the $35.06/boe received in 2011.

On a barrel of oil equivalent basis, during the period ended June 30, 2012 oil and NGL accounted for 41.67% of total sales and natural gas accounted for 58.33% of total sales, compared to 2011 when oil and NGL accounted for 19.8%, with natural gas accounted for 80.2% 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.

Six months ended June 30,	2012 ($)	2011 ($)	Percent Change (%)
Petroleum and natural gas revenue	88,456	609,440	(85.49)
Royalties, petroleum and natural gas	6,606	(66,915)	(109.87)
Production expenses, petroleum and natural gas	(118,473)	(344,626)	(65.62)
Operating netback, petroleum and natural gas	(23,411)	197,899	(111.83)
Net loss	(911,814)	(603,428)	51.11
Net loss per share (basic and diluted)	(0.01)	(0.01)	-
Revenue per boe	39.78	35.06	13.46
Royalty per boe	(2.97)	3.85	(177.14)
Operating costs per boe	53.28	19.83	168.68
Operating netback per boe	(10.52)	11.39	(192.36)

Petroleum and natural gas revenue decreased 85.49% to $88,456 for the six months ended June 30, 2012 from revenue of $609,440 during the six months ended June 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 by 13.46% to $39.78/boe from $35.06 during the six months ended June 30, 2012.

Royalties decreased by 109.87% to a recovery of $6,606 from $66,915 during the six months ended June 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 adjustment received from the government. Royalty per boe for the six months ended June 30, 2012 averaged ($2.97)/boe, which was an 177.14% decrease from $3.85/boe during the six months ended June 30, 2011.

Production expenses in the six months ended June 30, 2012 decreased to $118,473 from the six months ended June 30, 2011 of $344,626. The decrease was primarily due to the sale of certain oil and gas assets during the six months ended June 30, 2012. Operating costs/boe for the six months ended June 30, 2012 increased by 168.68% to $53.28/boe from $19.83/boe in the six months ended June 30, 2011.

Operating netback from petroleum and natural gas sales decreased to ($23,411) during the six months ended June 30, 2012 from $197,899 during the six months ended June 30, 2011. This decrease was mainly due to the sale of certain Canadian oil and gas assets.

Operating netback/boe decreased by 192.36% to ($10.52)/boe from $11.39/boe.

Royalties per unit of Production			
Six months ended June 30,	2012	2011	Percent Change %
Gas ($/mcf)	(2.28)	0.12	(2,000.00)
Oil ($/bbl)	5.39	4.27	26.23
NGL ($/bbl)	69.92	25.85	170.48
Total ($/boe)	(2.97)	3.85	(177.14)

The royalties per mcf for natural gas decreased to ($2.28)/mcf from $0.12/mcf in 2011. Oil royalties increased to $5.39/bbl from $4.27/bbl in 2011. NGL royalties increased to $69.92/bbl from $25.85/bbl in 2011. Combined royalties for all products decreased to ($2.97)/boe in 2012 from $3.85/boe the previous year.

GENERAL & ADMINISTRATIVE EXPENSES

After recoveries, general and administrative expenses ("G&A") increased to $327,845 and 607,594 during the three and six months ended June 30, 2012 from $285,663 and $587,475 for the same period during 2011. The increase is primarily due to the professional fees incurred to retire the bank debt, which amount to approximately $120,000. The Company continues to maintain efficiencies in all other general and administrative costs.

GENERAL & ADMINISTRATIVE EXPENSES						
	Three months ended June 30			**Six months ended June 30**		
	2012 ($)	2011 ($)	Percent Change (%)	2012 ($)	2011 ($)	Percent Change (%)
Net G&A expenses	327,845	285,663	14.77	607,594	587,475	3.42

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 $189,729 as at June 30, 2012. The decrease was primarily due to the disposal of certain Canadian oil and gas interests 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 June 30			**Six months ended June 30**		
	2012 ($)	2011 ($)	Percent Change (%)	2012 ($)	2011 ($)	Percent Change (%)
Depletion, depreciation and amortization	21,981	110,152	(80.04)	60,921	203,400	(70.05)

During the three and six months ended June 30, 2012, depletion and depreciation expenses were lower at $21,981 and $60,921 compared to $110,152 and $203,400 during the same period in 2011. The decrease was primarily due to the lower production volumes during 2012 compared to 2011 due the sale of the primary Canadian oil and natural gas assets during the six months ended June 30, 2012.

CASH FLOWS FROM OPERATIONS

During the six months ended June 30, 2012, cash flows used in operations increased to $790,130 from $485,280 at June 30, 2011. This increase was primarily due to lower sales revenue during 2012 and working capital fluctuations.

Funds used in operations during the six months ended June 30, 2012 increased to $840,471 from the previous year's $378,140. 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

Six months ended June 30,	2012 ($)	2011 ($)	Percent Change (%)
Capital expenditures	244,786	76,032	221.95

The increase in capital expenditures during 2012 as compared to 2011 was primarily due to increased investment in the Company's Texas oil and gas assets. During the six months ended June 30, 2012, the Company invested approximately $225,000 into these properties.

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 ($000 except per share and unit values)	**Jun 30 2012**	**Mar 31 2012**	**Dec 31 2011**	**Sep 30 2011**	**Jun 30 2011**	**Mar 31 2011**	**Dec 31 2010**	**Sep 30 2010**
Petroleum and natural gas sales	27	62	213	260	349	260	200	315
Net income (loss)	(641)	(270)	(1,524)	150	(150)	(555)	(1,668)	(357)
Net loss per share								
Basic and diluted	(0.01)	(0.00)	(0.03)	0.00	(0.00)	(0.01)	(0.04)	(0.01)
Average daily sales								
Natural gas (mcf/d)	14	81	296	401	501	423	470	553
Oil/NGL (bbls/d)	4	4	17	18	22	15	22	17
Barrels of oil equivalent (boe/d)	7	18	66	85	105	86	100	109
Average sales prices								
Natural Gas ($/mcf)	1.68	2.68	3.35	3.84	4.03	3.93	2.15	4.59
Oil/NGL ($/bbl)	60.55	110.31	77.19	69.86	83.45	78.91	66.09	52.69
Barrels of oil equivalent ($/boe)	43.19	38.49	34.79	33.20	36.47	33.33	24.37	31.42
Operating costs ($/boe)	116.72	29.06	17.93	18.01	20.52	18.97	16.32	13.77
Royalty Expense ($/boe)	(19.84)	3.47	5.44	5.76	3.42	4.38	5.66	5.49
Operating netback ($/boe)	(53.69)	5.95	11.41	9.43	12.53	9.98	2.39	12.16

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.

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 six months ended June 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 six months ended June 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 six months ended June 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 must 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 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 June 30, 2012, the Company had accrued $5,000 in interest.

As of the filing date of the interim financial statements of August 29, 2012, the Company has not made the $500,000 principal repayment required by August 15, 2012. Management anticipates this principal payment will be made with proceeds from equity financings during the remainder of 2012 and is currently negotiating with the Lender to reduce the repayment required.

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.

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

	August 29, 2012	**June 30, 2012**
Common Shares	103,041,689	98,199,959
Warrants (i)	43,729,431	38,887,701
Stock Options (ii)	7,380,000	7,380,000

Notes:

i) 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. 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.

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:

	June 30, 2012	December 31, 2011
	$	$
Note receivable from officer (i)	**234,878**	231,609
Fair value allowance (ii)	**(216,515)**	(216,515)
Net note receivable	**18,363**	15,094
Advance fees (iii)	**6,529**	9,529
	24,892	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 $18,363 at June 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 six months ended June 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 June 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 June 30:

(i) Aggregate fees of $57,300 (June 30, 2011 - $95,138) were charged by directors of the Company. Of this amount $57,300 (June 30, 2011 - $10,500) was recorded in the statement of comprehensive loss and $nil (June 30, 2011 - $84,638) was capitalized to property and equipment.

(ii) Aggregate fees of $nil (June 30, 2011 - $28,675) 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 $nil (June 30, 2011 - $13,125) was recorded in the statement of comprehensive loss and $nil (June 30, 2011 - $15,550) was capitalized to property and equipment.

For the six months ended June 30:

(iii) Aggregate fees of $127,125 (June 30, 2011 - $151,125) were charged by directors of the Company. Of this amount $127,125 (June 30, 2011 - $133,275) was recorded in the statement of comprehensive loss and $nil (June 30, 2011 - $17,850) was capitalized to property and equipment.

(iv) Aggregate fees of $nil (June 30, 2011 - $42,475) 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 $nil (June 30, 2011 - $23,925) was recorded in the statement of comprehensive loss and $nil (June 30, 2011 - $18,550) was capitalized to property and equipment.

(v) Included in accounts payable at June 30, 2012 was $99,270 owing to related parties of the Company (December 31, 2011 - $37,410).

Key management compensation

	June 30, 2012	December 31, 2011
	$	$
Compensation	**175,825**	362,912
Share based payments	**-**	60,393
Total	**175,825**	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 June 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.

SUBSEQUENT EVENTS

Subsequent to June 30, 2012, the Company closed a private placement through the issuance of 4,841,730 units for gross proceeds of $338,921. Each unit consists of one common share of the Company and one share purchase warrant (the "Warrant"). Each Warrant entitles the holder thereof to purchase 1 additional common share of the Company for a period of 12 months from the issuance of the units at a price of $0.10 per common share. The Warrants are subject to an acceleration clause whereby if after four months and one day following the date the Warrants are issued, the closing price of the common shares of the Company is equal to or exceeds $0.15 for 30 consecutive trading days, the Warrant expiry date shall accelerate to the date which is 30 calendar days following the date a press release is issued by the Company announcing the reduced Warrant term and all Warrant holders are notified.

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 six months ended June 30, 2012, the Company terminated the commodity call option for consideration of $116,114 and recognized an unrealized gain of $161,770 (June 30, 2011 – ($38,032) and $214,158, respectively) to reverse the financial contract liability recorded at December 31, 2011.

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

The Board of Directors oversees managements' establishment and execution of the Company's risk management framework. Management has implemented and monitors compliance with risk management policies. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

(a) Fair values

The Company's financial instruments consist of cash and cash equivalents, short-term investments, trade and other receivables, due from related parties, accounts payable and accrued liabilities, shareholder loan and long-term debt.

Financial Instrument	**Classification**	**Carrying Value $**	**Fair Value $**
Cash and cash equivalents	Fair value through profit and loss	9,328	9,328
Short-term investments	Fair value through profit and loss	50,018	50,018
Trade and other receivables	Loans and receivables	272,513	272,513
Due from related parties	Loans and receivables	24,892	24,892
Accounts payable and accrued liabilities	Other financial liabilities	2,428,108	2,428,108
Shareholder loan	Other financial liabilities	1,500,000	1,500,000
Long-term debt	Other financial liabilities	54,409	54,409

The significance of inputs used in making fair value measurements are examined and classified according to a fair value hierarchy. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement.

At June 30, 2012, the Company's cash has been subject to Level 1 valuation.

(b) Credit risk:

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from joint venture partners and oil and natural gas marketers.

Receivables from oil and natural gas marketers are normally collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers. The Company historically has not experienced any collection issues with its oil and natural gas marketers. Receivables from joint venture partners are typically collected within one to three months of the joint venture bill being issued. The Company attempts to mitigate the risk from joint venture receivables by obtaining partner pre-approval of significant capital expenditures. However, the receivables are from participants in the oil and natural gas sector, and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. In addition, further risk exists with joint venturers; as disagreements occasionally arise that increase the potential for non-collection. The Company does not typically obtain collateral from oil and natural gas marketers or joint venturers; however, the Company does have the ability to withhold production from joint venturers in the event of non-payment.

During the three and six months ended June 30, 2012, the Company recorded a recovery of $15,000 on bad debts recognized during the year ended December 31, 2011 and subsequently re-established the amount as a bad debt (December 31, 2011 – provision for doubtful accounts of $32,000).

Cash and cash equivalents consist of cash bank balances held in both interest and non-interest bearing accounts. The Company manages credit exposure of cash by selecting financial institutions with high credit ratings.

(c) Liquidity risk:

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Company's reputation.

To achieve this objective, the Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Company utilizes authorizations for expenditures on both operated and non operated projects to further manage capital expenditures. The Company also attempts to match its payment cycle with collection of oil and natural gas revenue on the 25th of each month.

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 (defined as current assets less current liabilities)	$2,063,501	This amount is anticipated to be met out of additional share issuance in the 2012.
Shareholder loan (note 11)	$1,500,000	The Company anticipates issuing additional share capital to reduce this amount in 2012. This amount is secured by the Company's oil and gas assets.
Long term debt	$54,409	Vehicle loans will be paid over the next 4 years out of normal cash flow.

(d) Market risk:

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates will affect the Company's income or the value of the financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while maximizing returns.

(i) Commodity price risk:

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by not only the relationship between the Canadian and United States dollar but also world economic events that dictate the levels of supply and demand. All of the Company's oil and gas production is sold at spot rates exposing the Company to the risk of price movements.

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 six months ended June 30, 2012, the Company terminated the commodity call option for consideration of $116,114 and recognized an unrealized gain of $161,770 (June 30, 2011 – ($38,032) and $214,158, respectively) to reverse the financial contract liability recorded at December 31, 2011.

The realized gain recorded by the Company on the commodity call option for the three and six months ended June 30, 2012 was $nil (June 30, 2011 – ($15,935) and $34,047, respectively).

(ii) Currency risk:

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

Certain of the Company's financial instruments are exposed to fluctuations in the US dollar, including cash and cash equivalents, accounts receivable and accounts payable and accrued liabilities. As at June 30, 2012, 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 $12,525 impact on the Company's comprehensive loss for the period.

(iii) Interest rate risk:

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its bank debt which bears a floating rate of interest. At June 30, 2012 the Company's bank debt was $nil; if interest rates had been 1% higher/lower, with all other variables held constant, there would have been an impact of approximately $8,300 on the Company's comprehensive loss for the period.

The Company has no interest rate swaps or financial contracts in place as at or during the three and six months ended June 30, 2012.

(e) Capital management:

The Company's capital consists of shareholders' equity, bank debt and working capital. The Company will adjust its capital structure to manage its current and future debt, drilling programs and potential corporate acquisitions through the issuance of shares, increasing the credit facility line and adjustments to capital spending. The Company's objective for managing capital is to maximize long-term Shareholder value by ensuring adequate capital to achieve the Company's objectives.

Management reviews its capital management approach on an ongoing basis and believes its current approach is reasonable given the size of the Company. There has been no change in managements approach to capital management during the year.

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.