MOUNTAINVIEW ENERGY LTD

Management's Discussion and Analysis

Year Ended December 31, 2012

Expressed in US Dollars

Management's Discussion and Analysis ("MD&A"), dated May 15, 2013, is management's assessment of the financial position and operating results of Mountainview Energy Ltd. (the "Company" or "Mountainview") and should be read in conjunction with the consolidated financial statements and the accompanying notes for the year ended December 31, 2012 and 2011. Additional information relating to the Company, are available on SEDAR at www.sedar.com. Mountainview is listed for trading on the TSX Venture Exchange under the symbols "MVW". All amounts are in US dollars, unless otherwise stated.

BASIS OF PRESENTATION

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

The reporting and the measurement currency is the US dollar. For the purpose of calculating unit costs, natural gas is converted to a barrel equivalent ("boe") using six thousand cubic feet of natural gas equal to one barrel of oil unless otherwise stated. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. The following MD&A compares the results of the year ended December 31, 2012 ("2012") to the year ended December 31, 2011 ("2011") and the results of the three months ended December 31, 2012 ("Q4 2012") to the three months ended December 31, 2011 ("Q4 2011").

MOUNTAINVIEW'S BUSINESS

Mountainview Energy Ltd. ("Mountainview" or "the Company") was incorporated under the laws of the Province of British Columbia, Canada and was continued into the Province of Alberta in May 2012. The Company is engaged in the exploration, development, acquisition and operation of petroleum and natural gas reserves properties through the drilling of horizontal Three Forks and Bakken wells on the Company's acreage located in the Williston Basin in Montana and North Dakota and the South Alberta Bakken Play in the State of Montana , USA.

FORWARD-LOOKING INFORMATION

Forward-Looking Statements

This MD&A contains certain forward-looking statements within the meaning of applicable securities laws. These statements relate to future events or future performance and are based on the Company's current expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Accordingly, undue reliance should not be placed on these forward-looking statements. The use of any of the words "expect", "anticipate", "continue", "estimate", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", and similar expressions are intended to identify forward-looking statements or information. In particular, but without limiting the foregoing, this MD&A contains forward-looking information concerning: the 2012 capital budget and allocation thereof; projected average production volumes for 2012; anticipated prices for oil and natural gas, including heavy oil; anticipated 2012 average operating expenses and the Company's ability to reduce such expenses; tax horizon and available tax pools; the remaining amount and allocation of the 2012 capital program; ability to fund the remaining capital program and the timing of funding our financial obligations. In addition, information and statements relating to oil and/or natural gas reserves are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

These forward-looking statements are based on certain key expectations and assumptions made by Mountainview, including but not limited to expectations and assumptions concerning: prevailing and future market prices for oil, natural gas, and in particular heavy oil differentials; prevailing and future foreign exchange rates, interest rates and inflation rates; applicable royalty rates, tax rates and related laws and regulations; future production rates; the performance of existing and future wells; the success obtained in drilling new wells; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour and services, including but not limited to drilling and completion equipment and services; adequate weather and environmental conditions for drilling and completion activities, including the transportation of associated equipment, the ability to obtain external sources of financing on acceptable terms; and the realization of the anticipated benefits of acquisitions.

Actual results achieved during the forecast periods will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties, the variances may be material. Such risks and uncertainties include: operational risks generally associated with oil and natural gas exploration, development, exploitation, production, transportation and marketing; volatility in market prices for oil, natural gas, and in particular heavy oil differentials; access to capital markets and stock price volatility; increased debt levels or debt service requirements; unanticipated fluctuations or declines in the Company's oil, natural gas production levels; adverse changes in legislation, including but not limited to tax laws, royalty rates and environmental regulations; ability to attract and retained qualified personnel; changes in the demand for Mountainview's products; fluctuations in foreign exchange rates, interest rates and inflation rates, risks associated with adverse weather, the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production rates, costs and

expenses; competition for, among other things, capital resources, acquisitions of reserves, undeveloped land and services.

Capital Expenditures, Acquisitions and Dispositions

On May 30, 2012 and July 18, 2012 the Company closed on the acquisition of 12,579 net acres of oil and gas leaseholds in Divide County, North Dakota from a private oil and gas company for $12,579,000.

In conjunction with this acquisition, the Company entered into two separate unsecured promissory notes payable with two separate major shareholders. The Company borrowed an aggregate of $8 million from such shareholders for a term of 2 years at an annual interest rate of 9.0%. The proceeds were used to fund $8 million of the $12,579,000 required in the acquisition. The Company is not required to repay any portion of the principal amount or any interest thereon prior to maturity (May 30, 2014), but may, at its option, repay any or all principal and interest amounts owing at any time prior to maturity. During the year ended December 31, 2012 the Company had repaid $150,000 to one of the major shareholders, in addition total interest paid at December 31, 2012 was $209,178 and accrued interest of $211,005.

Medicine Lake

The Company acquired certain non-producing oil and natural gas assets located in the Medicine Lake prospect in Divide County, North Dakota and Sheridan County, Montana, consisting of approximately 44,181 gross (8,836 net) acres of undeveloped land (the "Medicine Lake Assets") Mountainview acquired the Medicine Lake Assets in exchange for an aggregate of 23,110,020 Common Shares.
Total consideration for the acquisition of Medicine Lake was $7,790,580.

12 Gage

The Company acquired certain non-producing oil and natural gas assets located in the 12 Gage prospect in Divide County, North Dakota, consisting of approximately 12,579 net acres for total cash consideration of $12,579,000. The Company commenced a three well drill program in the 4th quarter 2012.

Pondera Business Acquisition

In May 2012, the Company closed a transaction to acquire assets in the Williams and Lake Frances areas of Pondera County, Montana, consisting of approximately 15,520 net acres of developed land and 31,593 net acres of undeveloped land (“Leaseholds”) in exchange for 5,027,273 common stock of the Company and 7,822,727 class B shares of a wholly owned subsidiary of the Company. The transaction was done as follows:

1. The Company acquired 100% of the three Canadian companies (holders of the 39% of the Leaseholds) and issued 5,027,273, common stock as consideration.

2. The Company's wholly owned US subsidiary then issued its common stock for the exchange of 100% of the Leaseholds to the three Canadian companies (intercompany transaction). This same US subsidiary then issued 7,822,727 of its class B shares to a company whose shareholder is also a Director and officer of the Company (holder of the 61% of the Leaseholds). These class B shares are convertible to common stock of the Company and therefore have been accounted as the Company's Equity.

3. The Company acquired the gathering system and compressor station in the Pondera County, Montana.

Fair value of net assets acquired:		
Oil and gas properties	$	2,048,990
Exploration and evaluation assets		2,179,917
Gathering system and compresor station		2,660,000
Decomissioning obligations		(26,805)
Total net assets acquired		6,862,102
Consideration:		
Common share		1,643,977
Class B shares		2,558,125
Cash		283,000
Convertible debenture		2,377,000
Total purchase price	$	6,862,102

This transaction has been identified as a business combination and the Company measured the identifiable assets and liabilities at fair value as determined by the Company through industry knowledge and activity in the region. As the consideration issued included exchangeable shares of the subsidiary for the Company these have been valued according to the quoted price of the shares of the Company based upon the exchange terms.

The Company also acquired the gathering system and compressor station used for the gas field on the Pondera property for $2,660,000 of which $283,000 was paid in cash and $2,377,000 (issued a convertible debenture of $2,072,053, which was reduced by costs incurred of $304,947 on behalf of the Company owned by a Director and officer prior to the transaction closing) was a debenture convertible into shares of the Company for $2.50 per share. Fair value measurement of the gathering system and compressor acquired involved the use of the replacement cost approach, which is based on the premise that a market participant would not pay more than the amount necessary to replace the asset. The convertible debt was recorded as its issuance amount which represents fair value.

Financing

On November 1, 2012, Mountain Divide, LLC, a subsidiary of the Company ("MD") entered into a Senior Secured Advancing Line of Credit Facility with Wells Fargo Energy Capital, Inc. (the "Credit Facility") for up to $75.0 million. The Facility includes an initial borrowing base of $19.0 million, which is to be used to fund the drilling of the Company's initial three wells in the 12 Gage Project. The Credit Facility matures in 32 months (July, 2015) and, bears interest at a float rate with an 8% minimum. Monthly repayments are required based on 85% of net revenues from the 12 Gage Project. In connection with

the Credit Facility, the lender and MD will have an area of mutual interest ("AMI"), which will be in northern Divide County, North Dakota. In addition, pursuant to the Facility, upon the earlier of the maturity date or the date the Facility is paid fully off, the Lender will trigger the start of a 39% after pay-out net profits interest (the "NPI") in all of the Company's oil and gas properties within Divide County, North Dakota.

The NPI is defined as all revenues received by the Company, less all operating costs, production taxes, and capital costs incurred by the Company. Payments on the NPI shall commence upon repayment in full of the outstanding Facility. The NPI will automatically reduce to 20% once the Lender achieves a 1.65 x return on investment. The Facility is secured by a first priority mortgage and security interest in the 12 Gage properties. The carrying amount of the collateral is $20,454,599. The borrowing base under the Facility will be subject to re-determination in the absolute discretion of the Lender within 45 days of the third well being turned into sales and thereafter semi-annually. The Company's subsidiary is required to maintain a current ratio of 1.0: 1.0.

The Company received proceeds of $3,883,071 under the Facility at December 31, 2012. The transaction has been recorded as a borrowing and a sale of conveyance relating to the 20% NPI. The Company has determined the fair value of the conveyance portion of the arrangement using a relative percentage of the conveyed property's fair value determined at its acquisition date and has recorded this amount of $2,622,912 as an adjustment to the property. The residual amount of the initial proceeds has been determined to be a borrowing and has been recorded as long term debt based upon the expected terms of repayment. The discount to the face amount of the debt will be accreted over the term of the debt.

Williston Basin

Since the closing of the acquisition of the 12 Gage Project, Mountainview has increased its acreage position to 13,007 net acres. This brings the Company's current acreage position in the Williston Basin to approximately 36,000 net acres. The Company has contracted with Nabors Rig 460 for a three-well drilling program in the 12-Gage Project targeting the Three Forks formation. The rig was moved to the Wigness 5-8-1H on November 4, 2012 and drilling operations commenced on November 15, 2012. Sanjel has been contracted to conduct cementing and fracturing services on this program. The Company projects well costs, including drilling, completion and tie-in to be $7-7.5 million (gross) per well. The company has identified 21 total initial drilling locations on its 12 Gage Project. Along with the Company's Stateline property, the Company currently has identified 46 initial operated drilling locations on its Williston Basin properties.

The following table outlines the Company's first three drilled wells on the 12 Gage Project:

Well Name	Operator	Working Interest	Net Revenue Interest	Spud Date	Current Status
Wigness 5-8-1H	Mountain Divide, LLC	93.75%	76.8067%	14-Nov-12	Producing
Leininger 3-10-1H	Mountain Divide, LLC	87.51%	69.9866%	12-Dec-12	Producing
Olson 35-26-1H	Mountain Divide, LLC	61.27%	49.2783%	5-Jan-13	Producing

4th Quarter Drilling Results

The Company began a three well drilling program in November 2012. The Company had at December 2012 started drilling two of the three wells. All three wells have been successfully completed subsequent to year end. For additional information on preliminary production performance please see News Releases dated February 5, March 19 and April 17, 2013.

Non-Operational Update – Williston Basin

To date the Company has participated in 13 (gross) Bakken/Three Forks wells in the Williston Basin. The following table lists the wells and their current status:

Well Name	Operator	Working Interest	Net Revenue Interest	Spud Date	Current Status
Olson 1-21-16H	G3 Operating, LLC	12.50%	10.0000%	4-Mar-11	Producing
Wolter 13-23H	SM Energy	3.25%	2.6000%	12-Sep-11	Producing
Strahan 15-22H	Hess Corporation	0.63%	0.5000%	1-Feb-11	Producing
Miller 157-101-12C-1-1H	Petro-Hunt LLC	0.79%	0.6296%	16-Nov-11	Producing
Zuma 15-22-35-58H	Samson Resources Company	9.75%	7.8000%	14-Jan-12	Producing
Riva Ridge 6-7-33-56H	Samson Resources Company	3.24%	2.5920%	11-Feb-12	Producing
Anton 3-4-163-101	American Eagle Energy Corp	3.38%	2.7040%	16-Jun-12	Producing
Muzzy	American Eagle Energy Corp	3.38%	2.7040%	26-Oct-12	Completing
Orville Hendrickson 24-12H	Marathon Oil Corporation	12.50%	9.7500%	18-Jun-12	Producing
Panther 16-21-1H	Zavanna, LLC	2.20%	0.2751%	11-Oct-11	Producing
Jaguar 1-22H	Zavanna, LLC	1.02%	0.1269%	14-Aug-11	Producing
Leopard 20-17-1H	Zavanna, LLC	1.02%	0.1269%	27-Feb-12	Producing
Quale	Whiting Oil & Gas Corporation	3.25%	2.6000%	14-Mar-12	Producing

During the annual period ending December 31, 2012 the Company acquired the following additional acreage in Montana and North Dakota:

Purchase of Non-core Assets

During 2012 the Company acquired various other oil and gas undeveloped properties for $1,069,252.

Non-core Asset Sale

The Company completed the sale of non-core oil and gas leases located in the Glacier and Toole County, Montana. The Company sold a 100% undivided working interest in 4,373.82 net acres of fee and state leases to an arm's length third party for $1,000,000 cash while retaining an overriding royalty interest in the leasehold. The Company recorded a gain of $576,269.

Results of operations

	Q4 2012	Q3 2012	Q2 2012	Q1 2012
Crude oil (Bbls per day)	149	134	117	136
Natural gas (Mcf per day)	337	335	241	29
Oil and natural gas as a percentage of production	**100%**	**100%**	**100%**	**100%**

	Q4 2011	Q3 2011	Q2 2011	Q1 2011
Crude oil (Bbls per day)	143	109	117	101
Natural gas (Mcf per day)	29	29	28	36
Oil and natural gas as a percentage of production	**100%**	**100%**	**100%**	**100%**

Oil production increased by 4% to 149 boe/d in Q4 2012 from 143 boe/d in Q4 2011. The Company increased revenues from its natural gas interests through the acquisition of the Pondera Business acquisition. Production of natural gas in Q4 2012 was 337 Mcf/d compared with 29 Mcf/d in Q4 2011.

Average Realized Prices

	Q4 2012	Q3 2012	Q2 2012	Q1 2012
Average benchmark prices				
Oil - WTI crude oil USD ($/Bbl)	87.96	90.83	93.48	102.89
Oil - CHS crude oil USD ($/Bbl)	73.31	74.83	73.20	85.51
Natural gas - AECO-C Daily spot ($/mcf)	3.08	2.19	1.82	2.52
Mountainview Average Realized Prices				
Crude oil ($/Bbl)	73.94	74.21	71.95	84.55
Natural gas ($/Mcf)	1.89	1.37	0.97	1.52
Average realized price ($/Boe)	**$ 75.83**	**$ 75.58**	**$ 72.92**	**$ 86.07**

	Q4 2011	Q3 2011	Q2 2011	Q1 2011
Average benchmark prices				
Oil - WTI crude oil USD ($/Bbl)	97.82	84.89	96.23	94.13
Oil - CHS crude oil USD ($/Bbl)	83.64	78.12	90.85	82.38
Natural gas - AECO-C Daily spot ($/mcf)	3.37	3.86	3.89	3.71
Mountainview Average Realized Prices				
Crude oil ($/Bbl)	82.60	77.03	91.04	81.10
Natural gas ($/Mcf)	1.78	2.14	2.04	2.01
Average realized price ($/Boe)	**$ 84.38**	**$ 79.17**	**$ 93.08**	**$ 83.11**

The majority of the Company's crude oil production consists of heavy oil which ranges in quality from 22 degree to 34 degree API, seen in the Montana, South Alberta properties. In addition, the oil production in the Stateline/Medicine Lake acreage located in the Montana and North Dakota, Williston Basin properties is 42 degree API, sweet crude oil quality. The Company's realized prices are reflected net of the blending charges required for heavier crudes to be transported by pipeline. Subsequent to year-

end our sweet crude oil production increased due to the 12-Gage development project. The average price received per barrel of oil for January 2013 was $92.32 and $89.21 for February 2013.

The Company realized an average oil price of $76.16/bbl for the year ended December 31, 2012 which is an 8% decrease from the $82.94/bbl realized for the year ended December 31, 2011.

The Company's natural gas is sold under marketing arrangements tied to the Alberta daily spot price at AECO, with a premium or discount received specific to the quality (based on heat-content) of the Company's natural gas production. The Company realized an average natural gas price of $1.44/mcf for the year ended December 31, 2012 which is a 27% decrease from the $1.99/mcf from the year ended December 31, 2011

Revenue

	Q4 2012	Q3 2012	Q2 2012	Q1 2012	2012
Crude oil sales	$ 689,681	$ 920,215	$ 716,916	$ 1,061,329	$ 3,388,141
Natural gas	88,490	41,224	31,870	10,057	171,641
Gross oil and natural gas revenues	**$ 778,171**	**$ 961,439**	**$ 748,786**	**$ 1,071,386**	**$ 3,559,782**

	Q4 2011	Q3 2011	Q2 2011	Q1 2011	2011
Crude oil sales	$ 928,840	$ 796,781	$ 941,910	$ 730,827	$ 3,398,358
Natural gas	9,562	10,892	9,919	10,769	41,142
Gross oil and natural gas revenues	**$ 938,402**	**$ 807,673**	**$ 951,829**	**$ 741,596**	**$ 3,439,500**

Total oil and gas revenue during the three and twelve months ended Q4 2012 decreased and increased during Q4 2012 at $778,171 and $3,559,782 from the $938,402 and $3,439,500 reported in Q4 2011.

Total oil and gas revenue during the year ended December 31, 2012 increased by $120,282 from the year ended December 31, 2011. The Company experienced a .3% decrease in oil sales of $10,217 during the year ended December 31, 2012 from the year ended December 31, 2011. This resulted from lower realized oil prices.

Royalties

Royalties are paid to mineral owners, which may include freehold landowners and other parties by way of contractual overriding royalties. Royalty rates are generally dependent on commodity prices and well productivity.

Total royalties expense during the three and twelve months ended Q4 2012 were $104,514 and $298,547, from $80,478 and $314,559 in Q4 2011 due to increased sales volumes and revenues.

Operating Expenses

Significant components of the Company's operating expenses include well servicing, fuel and power, labour and production taxes. The total operating expenses for the three and twelve months ended Q4 2012 increased by 47% and 13% to $687,237 and $1,799,832, from $323,493 and $1,584,852 in Q4 2012. Operating expenses increased due to labour and consulting, repairs and maintenance, and materials.

	Year ended December 31,	
	2012	2011
Labour and consulting	$ 361,207	$ 341,496
Production and property taxes	200,190	328,996
Repairs and maintenance	505,716	267,183
Materials	276,288	212,974
Electrical	168,893	159,841
Vehicle	129,519	136,531
Engineering	63,993	56,336
Other production costs	58,708	86,392
Insurance	30,197	13,753
Beginning Inventory	23,665	5,014
Ending Inventory	(18,544)	(23,665)
	$ 1,799,832	$ 1,584,852

There was a major increase in the cost of repairs and maintenance. This was a result of the cost of replacing and repairing bottom-hole pumps in wells currently producing. This process requires a service rig, which adds to the cost of the procedure. In addition, the Company conducted a number of acid treatments to enhance production from existing wells, the procedure which also requires a service rig. The Company saw a $50 per hour increase for rig services during the year, as well as an increase in the cost for acid stimulation and bottom-hole equipment. Along with these costs the Company incurred one-time costs for a communications system overhaul, which required an upgrade of the existing electrical system and the installation of new electrical equipment on the injection system at the Red Creek Field. The Company also incurred costs related to plant turnaround for the gathering system and compressor station. The Company acquired the gathering system and compressor station during the year and this did not have these expenditures in the previous year.

The Company saw a large increase in the cost of materials and supplies, mainly due to the installation of chemical pumps in existing wells along with the purchase of chemical to treat existing wells to prevent scale buildup and corrosion. The Company saw a $3.00 per barrel increase for this chemical during the year.

Total production taxes during the year ended December 31, 2012 decreased by $128,064 from the year ended December 31, 2011. The production taxes during the year ended December 31, 2011 increased by $9,045 from the year ended December 31, 2010. At the end of each year the Company can apply to have a reduced production tax rate. In order to qualify for a reduced rate the wells on average produce

less than 3bbls/per day. At the end of 2011 the Company qualified for a reduced stripper rate on the Red Creek property which reduced the rate from 9.26 – 11.26% to a flat rate of 6.26%.

General and Administrative Expense

The Company recorded G&A expenses for the three and twelve months ended in Q4 2012 of $711,315 and $1,726,042 a decrease of 3% and 11% from $734,743 and $1,940,116 in Q4 2011.

As set out below the G&A expenses from the current and prior year.

	Year ended December 31,	
	2012	2011
Travel and promotion	$ 383,407	$ 524,960
Salaries and Wages	485,678	331,527
Legal Fees	180,170	320,002
Accounting and Auditing	268,388	269,727
Office expense	104,771	180,285
Shareholder relations	111,279	121,611
Investor Relations	40,184	56,605
Listing and filing fees	6,671	52,005
Director fees	15,504	23,097
Insurance	58,456	21,742
Professional fees	50,000	19,441
Transfer Agent Fees	21,534	19,115
	$ 1,726,042	$ 1,940,116

The large increase in salaries and wages, insurance and professional fees relates directly to the Company expanding its operations.

The Company saw a significant decrease in travel and promotion, legal fees, office expense and listing and filing fees. These costs decreased in the current year as a result of acquisitions being completed. These costs were necessary to facilitate the acquisition transactions completed during the year along with securing financing to move forward with the Company's development plan in the South Alberta Bakken Play in Montana and the Three Forks/Bakken Play in the Williston Basin, located in Montana and North Dakota.

Share-based Compensation Expense

Share-based compensation expense is a non-cash item representing the estimated fair value of the stock options granted to employees and others, recognized when the options vest. The Company recorded in the three and twelve months ended Q4 2012 $94,347 and $94,347 of share-based compensation and $nil and $3,597,911 in Q4 2011.

Depletion, accretion and Depreciation Expense

Depletion, accretion and depreciation of property, plant and equipment is calculated on the unit-of-production basis using depletable capital costs, production and estimated proved plus probable reserves. Depletion, accretion and depreciation expense in the three and twelve months ended increased to $683,975 and $1,479,268 in Q4 2012 an increase over $499,048 and $872,483 from Q4 2011. Increase in depletion, accretion and depreciation expense relates to the purchase of additional vehicles and an additional well that the company has a joint interest in.

Impairment of Oil and Natural Gas Properties

At December 31, 2012, due to the indicators of possible impairment, the Company reviewed the carrying value of the oil and gas properties by cash generating units for impairment. As a result of the review, it was determined that the oil and gas properties were impaired and an impairment charge of $6,903,662 was recognized to reduce the carrying value to the recoverable amount. The recoverable amount was determined based on the fair value less cost to sell method using discounted future cash flows at a discount rate of 12%. The estimated future cash flows utilized in the calculation incorporated the Company's best estimates of future oil and gas production based on the current plans, estimates of future oil and gas prices, operating costs and residual values.

Capitalized Interest and Interest Expense

At December 31, 2012 and 2011, the Company, had capitalized interest of $717,345 and $Nil, and interest expense of $295,652 and $5,260. The Company, has capitalized interest related to the 12 Gage property development. Interest expense during the year increased as a result of the Company obtaining additional financing to expand its operations.

Going Concern

These consolidated financial statements have been prepared on a going concern basis, which assumes the realization of assets and liquidation of liabilities in the normal course of business. The Company has experienced losses in the years ended December 31, 2012 and 2011. At December 31, 2012, and 2011 the Company had a deficit of $11,526,480 and $3,129,577 respectively and working capital (deficit) of ($17,481,721) and $112,573 respectively Continuing operations, as intended, are dependent on management's ability to raise required funding through future equity issuances, credit facilities, asset sales or a combination thereof, which is not assured, especially in today's volatile and uncertain financial markets. There can be no assurance that management's plans will be successful. These uncertainties cast substantial doubt on the entity's ability to continue as a going concern. These consolidated financial statements do not include any adjustments to the recoverability and classification of recorded asset amounts and classification of liabilities that might be necessary, should the Company be unable to continue as a going concern.

Liquidity and Capital Resources

As of December 31, 2012, our assets totaled $49,055,600, which included, among other items, cash balances totaling $460,270, trade receivables totaling $820,948, including amounts due from our working interest partner totaling $440,224. Our working capital deficit as of December 31, 2012 was ($17,481,721) compared to $112,573 as of December 31, 2011.

As of December 31, 2012, we had accounts payable of $8,576,036, outstanding bank debt of $8,494,000, a convertible debenture of $2,123,947, promissory notes payable of $8,061,005 credit facility of $1,004,308 and long-term debt of $120,257. As of December 31, 2011, we had long-term debt of $124,473.

The Company acquired from a company owned by a Company that is 50% owned by a Director and officer, a compressor plant and equipment for consideration of $2,660,000. The Company paid $283,000 (deposit paid March 31, 2011) and agreed to issue a $2,377,000 (issued a convertible debenture of $2,072,053, which was reduced by costs incurred of $304,947 on behalf of the Company owned by a Director and officer prior to the transaction closing) debenture convertible into common shares of the Company at a price of $2.50 per share. The maturity date of the debenture is on or before June 1, 2013. At December 31, 2012 the convertible debenture was $2,072,053 plus accrued interest of $51,894. At December 31, 2012, if the convertible debenture had been converted the Company would have issued 828,821 additional common shares of the Company.

On April 17, 2012, the Company entered into a revolving line of credit with First Interstate Bank for $5,500,000 and on June 27, 2012, increased the line of credit to $8,700,000 (the “Credit Line”). The outstanding balance at December 31, 2012 was $8,494,000. The Credit Line is secured by the assets of the Company and guaranteed by our Chief Executive Officer and by a significant shareholder. Interest is payable monthly at a variable rate of prime plus 1.25%. The minimum interest rate is 5.25%. The Line of Credit is due June 17, 2013.

On November 1, 2012, MD entered into the Credit Facility. MD had received $3,883,071 under the Credit Facility at December 31, 2012, and recorded $2,622,912 relating to the sale of the 20% NPI. The Company has determined the fair value of the conveyance portion of the arrangement using a relative percentage of the conveyed property’s fair value determined at its acquisition date and has recorded this amount of $2,622,912 as an adjustment to the property. The residual amount of the initial proceeds has been determined to be a borrowing and has been recorded as long term debt based upon the expected terms of repayment. The discount to the face amount of the debt will be accreted over the term of the debt. The offsetting entry will be to the 12 Gage property until production commences and then will be expensed until maturity.

The Company has various vehicle loans outstanding at December 31, 2012 and 2011 of $179,032 and $180,292, respectively. The loans vary from 0% interest to 4% and will be repaid in less than five years.

The Company entered into two promissory notes payable with major shareholders of the Company, each for $4,000,000 (total $8,000,000), bearing interest at 9% per annum and drawdown of the full

principal balance. The principal is payable on or before May 30, 2014 and the interest is payable quarterly. During 2012 the Company repaid $150,000 on one of the promissory notes, has paid interest of $209,178 and has accrued interest of $211,005.

Historically, we have successfully raised additional operating capital through private equity funding sources and from the sale oil and gas generated revenues.

Net Earnings (Loss)

	Year ended December 31, 2012	2011
Net income (loss) for the year	$ (8,396,903)	$ (4,736,238)
Weighted average shares - basic and diluted	75,836,349	49,208,929
Income (loss) per share - basic and diluted	$ (0.11)	$ (0.10)

The Company reported a net loss in 2012 of $8.3 million or $0.11 per share. The loss relates to the large impairment of oil and natural gas assets of $6.9 million. The Company's net loss for the year ended 2011 was $4,736,238 or $0.10 per share.

Equity

The Company's equity structure consists of common shares outstanding and stock options outstanding to acquire additional common shares on a one for one basis. The Company's common shares are listed on the TSX Venture Exchange under the trading symbol MVW.

	May 15, 2013	December 31, 2012	December 31, 2011
Number of securities outstanding			
Common Shares	87,245,443	87,245,443	59,108,150
Total exercisable stock options	3,536,389	3,536,389	4,130,000

Taxes

The Company reported a current tax expense of $90,382 for the year ended December 31, 2012 compared to $63,193 in 2011. In 2012, the Company had no deferred tax expense/recovery and in 2011 the Company recorded a deferred tax recovery of $139,269.

Related Party Transactions

Please refer to Note 15 of our consolidated financial statements for related party transactions during the year ended December 31, 2012.

Segment Information

Please refer to Note 23 of our consolidated financial statements for segment information for the year ended December 31, 2012.

Financial Instruments and Risk Management

Mountainview is subject to a number of financial risks, including market risk, liquidity risk and credit risk. Market risk is the risk that the fair value of future cash flows will fluctuate due to movements in market prices, as comprised of commodity price risk, foreign exchange rate risk and interest rate risk. Market risk is managed by Mountainview through ongoing monitoring of the markets. Liquidity risk is the risk that the Company will encounter financial difficulty in meeting obligations associated with financial liabilities. Mountainview manages its liquidity risk through cash and debt management and review of financial ratios. Credit risk is the risk that a counterparty to a financial asset will default resulting in the Company incurring a loss. Mountainview manages credit risk by entering into sales contracts with creditworthy entities and reviewing its exposure to individual entities on a regular basis. Details of risk management contracts in place at December 31, 2012 and the accounting treatment of the Company's financial instruments are disclosed in the notes to the consolidated financial statements as at and for the year ended December 31, 2012.

Off-Balance Sheet Arrangements

The Company has no off-balance sheet arrangements.

CRITICAL ACCOUNTING ESTIMATES

Management is often required to make judgments, assumptions and estimates in the application of IFRS that may have a significant impact on the financial results of the Company. The preparation of financial information in accordance with IFRS requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. The following is a summary of key areas where critical accounting estimates are made:

Financial statement item and Critical accounting estimates

Depletion and depreciation expense

Accumulated costs are depleted using the unit-of-production method based on estimated proved reserves. Depletion is calculated based on individual components (i.e. fields or combinations thereof and other major components with different useful lives).

Impairment of non-current assets

The carrying amounts of the Company's property, plant and equipment are reviewed at each reporting date for indicators of impairment. If any such indication exists, the recoverable amount of the asset is estimated in order to determine the amount of the impairment, if any. The recoverable amount of an asset is evaluated at the Cash Generating Unit ("CGU") level, which is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The recoverable amount of a CGU is the greater of its fair value less costs to sell and its value in use. Fair value is determined as the amount that would be obtained from the sale of the asset in an arm's length transaction between knowledgeable and willing parties, less the costs of disposal. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. An impairment loss is recognized in earnings for the period to the extent that the carrying amount of the asset (or CGU) exceeds the recoverable amount.

Impairment losses recognized in prior periods are assessed at each reporting date for any indication that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimate used to determine the recoverable amount. An impairment loss is reversed only to the extent that the carrying amount of the asset (or CGU) does not exceed the carrying amount that would have been determined, net of depletion and depreciation, had no impairment loss been recognized for the asset (or CGU). A reversal of an impairment loss is recognized immediately in earnings.

E&E assets are assessed for impairment when they are reclassified to property, plant and equipment, or if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

Exploration and evaluation (“E&E”) costs

Once the legal right to explore has been acquired, costs directly associated with the exploration project are capitalized as either tangible or intangible exploration and evaluation assets according to the nature of the asset acquired. Such E&E costs may include undeveloped land acquisition, geological, geophysical and seismic, exploratory drilling and completion, testing, decommissioning and directly attributable internal costs. E&E costs are not depleted and are carried forward until technical feasibility and commercial viability of extracting a mineral resource is considered to be determined. The technical feasibility and commercial viability of an oil and gas resource is considered to be established when proved and/or probable reserves are determined to exist. All such carried costs are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the exploratory activity. When this is no longer the case, the impairment costs are charged to exploration and evaluation expense. Upon determination of proved and/or probable reserves, E&E assets attributed to those reserves are first tested for impairment and then reclassified to oil and gas development and production assets within property, plant and equipment, net of any impairment. Expired land costs are also expensed to exploration and evaluation expense as they occur.

E&E assets are assessed for impairment if facts and circumstances suggest that the carrying amount exceeds the recoverable amount, and upon transfer to property, plant and equipment whereby they are allocated to cash-generating units based on geographical proximity and other factors.

Decommissioning liabilities

Decommissioning liabilities are recognized for the future legal or constructive obligation to abandon and reclaim the Company's oil and natural gas properties. The amount of the decommissioning liabilities represents the net present value of the estimated future expenditures required to abandon and reclaim the Company's net ownership in wells and facilities determined in accordance with local conditions, current technology and current requirements. The liabilities are calculated using currently estimated abandonment and reclamation costs inflated to the estimated decommissioning date and then discounted using a risk free discount rate. A liability is recorded in the period in which an obligation arises with a corresponding decommissioning cost added to the carrying amount of the related asset. The liability is progressively accreted over time as the effect of discounting unwinds, creating an accretion expense which is recognized as part of finance expense. The related decommissioning cost capitalized in property, plant and equipment is depreciated in a manner consistent with the depletion and depreciation of the underlying asset.

Changes in the estimated liability resulting from revisions to estimated timing of decommissioning, expected amount of cash flows or changes in the discount rate are recognized as a change in the decommissioning liability and the related decommissioning cost.

Actual decommissioning expenditures incurred are charged against the accumulated liability to the extent recorded.

Share-based payments

The grant date fair value of options to employees and directors is recognized as share-based compensation expense, with a corresponding increase in contributed surplus, over the vesting period of the options. Share-based payments to non-employees are measured at the fair value of the goods or services received or the fair value of the equity instruments issued if it is determined the fair value of the goods or services cannot be reliably measured, and are recorded at the date the goods or services are received. Each tranche in an award is considered a separate grant with its own vesting period and grant date fair value. Fair value is determined using the Black-Scholes option pricing model. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest. Upon the exercise of stock options, the consideration received by the Company plus the associated amount recorded in contributed surplus are transferred to common shares within equity.

Deferred income taxes

The tax expense for the period comprises current and deferred tax. Tax is recognized in the statement of loss, except to the extent that it relates to items recognized in other comprehensive loss or directly in equity. In this case, the tax is also recognized in other comprehensive loss or directly in equity, respectively. The current income tax charge is calculated on the basis of the tax laws enacted or

substantively enacted at the balance sheet date in the countries where the company and its subsidiaries operate and generate taxable income.

Management periodically evaluates positions taken in tax returns with respect to situations in which applicable tax regulation is subject to interpretation. It establishes provisions where appropriate on the basis of amounts expected to be paid to the tax authorities.

Deferred income tax is recognized, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the consolidated financial statements. However, deferred tax liabilities are not recognized if they arise from the initial recognition of goodwill; deferred income tax is not accounted for if it arises from initial recognition of an asset or liability in a transaction other than a business combination that at the time of the transaction affects neither accounting nor taxable profit or loss. Deferred income tax is determined using tax rates (and laws) that have been enacted or substantially enacted by the date of the statement of financial position and are expected to apply when the related deferred income tax asset is realized or the deferred income tax liability is settled.

Subsequent Events

There are no subsequent events.

Future Changes in Accounting Policies

The following accounting standards have been issued or amended and are effective for future reporting periods. The Company is evaluating the impact of these new or amended standards and a more detailed description of these policies is disclosed in note 3 t) to the consolidated financial statements for the year ended December 31, 2012:

IFRS 7	Financial Instrument Disclosures
IFRS 10	Consolidated Financial Statements
IFRS 11	Joint Arrangements
IFRS 12	Disclosure of Interest in Other Entities
IFRS 13	Fair Value Measurement
IAS 32	Financial Instruments Presentation

Controls and procedures

In connection with Exemption Orders issued in November 2007 and revised in December 2008 by each of the securities commissions across Canada, the Chief Executive Officer and Chief Financial Officer of the Company will file a Venture Issuer Basic Certificate with respect to the financial information contained in the unaudited interim financial statements and the audited annual financial statements and respective accompanying Management's Discussion and Analysis.

In contrast to the certificate under National Instrument ("NI") 52-109 (Certification of disclosure in an Issuer's Annual and Interim Filings), the Venture Issuer Basic Certification does not include

representations relating to the establishment and maintenance of disclosure controls and procedures and internal control over financial reporting, as defined in NI 52-109.

Disclosure controls and procedures

Disclosure controls and procedures ("DC&P") are intended to provide reasonable assurance that information required to be disclosed is recorded, processed, summarized and reported within the time periods specified by securities regulations and that information required to be disclosed is accumulated and communicated to management. Internal controls over financial reporting ("ICFR") are intended to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purpose in accordance with Canadian generally accepted accounting principles.

TSX-V listed companies are not required to provide representations in the annual filings relating to the establishment and maintenance of DC&P and ICFR, as defined in Multinational Instrument 52-109. In particular, the CEO and CFO certifying officers do not make any representations relating to the establishment and maintenance of (a) controls and other procedures designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation, and (b) a process to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP.

The issuer's certifying officers are responsible for ensuring that processes are in place to provide them with sufficient knowledge to support the representations they are making in their certificates regarding the absence of misrepresentations and fair disclosure of financial information. Investors should be aware that inherent limitations on the ability of certifying officers of a TSX-V issuer to design and implement on a cost effective basis DC&P and ICFR as defined in Multinational Instrument 52-109 may result in additional risks to the quality, reliability, transparency and timeliness of interim and annual filings and other reports provided under securities legislation.

Risk Factors

Financial Risk

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions that could have a positive or negative impact on Mountainview's business. Financial risks the Company is exposed to include: marketing reserves at an acceptable price given market conditions; finding and producing reserves at a reasonable cost; volatility in market prices for oil and natural gas; fluctuations in foreign exchange and interest rates; stock market volatility; debt service which may limit timing or amount of dividends as well as market price of shares; the continued availability of adequate debt and equity financing and cash flow to fund planned expenditures; sufficient liquidity for future operations; lost revenue or increased expenditures as a result of delayed or denied environmental, safety or regulatory approvals; cost of capital risk to carry out the Company's operations; and uncertainties associated with credit facilities and counterparty credit risk.

Operational Risk

Operational risk is the risk of loss or lost opportunity resulting from operating and capital activities that, by their nature, could have an impact on the Company's ability to achieve objectives. Operational risks Mountainview is exposed to include: uncertainties associated with estimating oil and natural gas reserves; incorrect assessments of the value of acquisitions and exploration and development programs; failure to realize the anticipated benefits of acquisitions; uncertainties associated with partner plans and approvals; operational matters related to non-operated properties; delays in business operations, pipeline restrictions, blowouts; unforeseen title defects; increased competition for, among other things, capital, acquisitions of reserves and undeveloped lands; competition for and availability of qualified personnel or management; loss of key personnel; unexpected geological, technical, drilling, construction and processing problems; availability of insurance; competitive action by other companies; the ability of suppliers to meet commitments and risks; and uncertainties related to oil and gas interests.

Safety, Environmental and Regulatory Risks

Safety, environmental and regulatory risks are the risks of loss or lost opportunity resulting from changes to laws governing safety, the environment, royalties and taxation. Safety, environmental and regulatory risks Mountainview is exposed to include: uncertainties associated with regulatory approvals; uncertainty of government policy changes; the risk of carrying out operations with minimal environmental impact; changes in or adoption of new laws and regulations or changes in how they are interpreted or enforced; obtaining required approvals of regulatory authorities and stakeholder support for activities and growth plans. There are no new material environmental initiatives impacting Mountainveiw at this time.

Risk Management

Mountainview is committed to identifying and managing these risks in the near term, as well as on a strategic and longer term basis at all levels in the organization in accordance with our Board-approved Risk Management and Counterparty Credit Policy and risk management programs. Issues affecting, or with the potential to affect, our assets, operations and/or reputation, are generally of a strategic nature or are emerging issues that can be identified early and then managed, but occasionally include unforeseen issues that arise unexpectedly and must be managed on an urgent basis. Mountainview takes a proactive approach to the identification and management of issues that can affect the Company's assets, operations and/or reputation and have established consistent and clear policies, procedures, guidelines and responsibilities for issue identification and management. Specific actions Mountainview takes to ensure effective risk management include: employing qualified professional and technical staff; concentrating in a limited number of areas with low cost exploitation and development objectives; utilizing the latest technology for finding and developing reserves; constructing quality, environmentally sensitive and safe production facilities; adopting and communicating sound policies governing all areas of our business; maximizing operational control of drilling and production operations; adhering to conservative borrowing guidelines; monitoring counterparty creditworthiness and obtaining counterparty credit insurance.

Selected Annual Information

Set out below is selected annual information for Mountainview for the last three years:

	2012	2011	2010
Oil and natural gas sales	$ 3,559,782	$ 3,439,500	$ 2,900,253
Royalties	298,547	314,559	246,015
Operating expense	1,799,832	1,584,852	1,171,588
Depletion, accretion and depreciation	1,479,268	872,483	698,982
	(17,865)	667,606	783,668
General and administrative expense	1,726,042	1,940,116	878,964
Impairment of oil and natural gas assets	6,903,662	-	-
Gain on sale of oil and natural gas assets	(576,269)	-	-
Interest expense	295,652	5,260	1,416
Interest income	(3,692)	(15,896)	(10,756)
Loss from operations	(8,363,260)	(1,261,874)	(85,956)
Per share - Basic and diluted	(0.11)	(0.03)	(0.01)
Net income (loss)	(8,396,903)	$ (4,736,238)	$ 371,470
Per share - Basic and diluted	(0.11)	(0.10)	0.04
Exploration and evaluation assets	14,737,242	6,397,705	512,927
Property, plant and equipment	92,168	255,389	54,453
Oil and gas property	6,294,679	1,250,378	-
Dispositions	(3,622,913)	-	(174,149)
Net debt	26,788,367	11,900	-
Total assets	49,055,600	$ 19,151,591	$ 6,634,616
Weighted Average Shares outstanding			
Basic	75,836,349	49,208,929	9,766,850
Diluted	75,836,349	49,208,929	9,766,850

Summary of Quarterly Results

	Q4 2012	Q3 2012	Q2 2012	Q1 2012
Net Revenue	$ 732,602	$ 959,243	$ 704,659	$ 1,011,233
Net Income (Loss)	$ (7,339,991)	$ (428,315)	$ (366,292)	$ (262,305)
Income (Loss) per Share - Basic	$ (0.10)	$ (0.00)	$ (0.01)	$ (0.00)
Income (Loss) per Share - Diluted	$ (0.10)	$ (0.00)	$ (0.01)	$ (0.00)
Total Assets	$ 49,055,600	$ 49,359,566	$ 47,945,130	$ 21,248,818
Total Liabilities	$ 28,823,571	$ 21,926,374	$ 20,083,623	$ 4,879,397

	Q4 2011	Q3 2011	Q2 2011	Q1 2011
Net Revenue	$ 994,900	$ 762,979	$ 910,768	$ 647,331
Net Income (Loss)	$ (611,520)	$ (503,778)	$ 28,140	$ (3,649,080)
Income (Loss) per Share - Basic	$ (0.01)	$ (0.01)	$ 0.00	$ (0.13)
Income (Loss) per Share - Diluted	$ (0.01)	$ (0.01)	$ 0.00	$ (0.13)
Total Assets	$ 19,151,591	$ 23,840,827	$ 22,340,454	$ 22,203,472
Total Liabilities	$ 2,519,865	$ 1,764,716	$ 1,706,591	$ 1,566,515