MOUNTAINVIEW ENERGY LTD

Management's Discussion and Analysis

Nine Months Ended September 30, 2013

Expressed in US Dollars

Management's Discussion and Analysis ("MD&A"), dated November 28, 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 interim consolidated financial statements and the accompanying notes for the period ended September 30, 2013 and 2012. Additional information relating to the Company, are available on SEDAR at www.sedar.com. Mountainview is listed for trading on the TSX Venture Exchange ("**TSX-V**") under the symbol "MVW". All amounts are in US dollars, unless otherwise stated.

BASIS OF PRESENTATION

The condensed interim consolidated financial statements, including comparatives, have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") applicable to the preparation of interim financial statements, including IAS 34, "Interim Financial Reporting". The condensed consolidated interim financial statements should be read in conjunction with the annual consolidated financial statements for the year ended December 31, 2012, which have been prepared in accordance with IFRS as issued by the IASB.

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 three and nine months ended September 30, 2013 ("2013") to the three and nine months ended September 30, 2012 ("2012").

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. Although management believes that such expectations 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 2013 capital budget and allocation thereof; projected average production volumes for 2013; anticipated prices for oil and natural gas; anticipated 2013 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 2013 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; 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 and/or natural gas; 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; and competition for, among other things, capital resources, acquisitions of reserves, undeveloped land and services.

Capital Expenditures, Acquisitions and Dispositions

Williston Basin

During the nine-month period ending September 30, 2013, the Company successfully drilled and completed four wells in the 12-Gage Project located in Divide County, ND. Following are the most recent results for the four wells completed during the period. These results include natural gas being flared at the wellhead.

- The Wigness 5-8-1H well, the first horizontal Three Forks well in the winter drilling program, has been on production since March 2013. To-Date the Wigness well has produced 43,881 boe (41,702 boe net) 90% oil and had an average daily production rate of 239 boe/day (224 boe/d net) 90% oil for the month of September 2013.

- The Leininger 3-10-1H well, the second horizontal Three Forks well in the winter drilling program, has been on production since April 2013. To-date the Leininger well has produced 47,426 boe (41,502 boe net) 90% oil and had an average daily production of 280 boe/day (245 boe/day net) 90% oil for the month of September 2013.

- The Olson 35-26-1H well, the third horizontal Three Forks well in the winter drilling program, has been on production since April 2013. To-date the Olson well has produced 33,105 boe 20,284 boe net) 90% oil and had an average daily production of 189 boe/d (116 boe/d net) 90% oil for the month of September 2013.

- The Heckman 7-6-1H well (the "Heckman Well"), the fourth well drilled in the 12-Gage Project has been on production since September 2013. The initial 7 day average production on this well was 532 boe/d gross (477 boe/d net) of 90% oil. The Heckman Well had a 30 day initial production of 441 boe/d gross (396 boe/d net) of 90% oil. This well has exceeded Company production expectations thus far.

These are field production rates not sales.

The Company achieved its goal of reducing drilling and completion costs from $8.0-$8.3 million on its 2013 winter drilling program in the 12 Gage Project to approximately $6.5-$7.0 million for the 2013 summer drilling program.

The Company is also pleased to announce that Nick Timm has joined the Mountainview team as a full time Field Supervisor for the 12 Gage Project. Mr. Timm, who was previously employed by a reputable operator in the area, brings nearly 10 years of operational field-based experience to the team.

(Reported in US Dollars, unless otherwise indicated)

Mountainview has increased its artificial lift capabilities on all of its operated Three Forks wells by deploying an ESP (Electric Submersible Pump) in each well. This artificial lift change in the wells has increased production in the first three wells of the 2013 drilling program by approximately 35% and is expected to have a significant positive impact on production levels for the three 'new' wells; the Heckman 7-6-1H, the Olson 2-11S-1H and the Charlotte 1-12-1H..

The following table outlines the Company's 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
Heckman 7-61H	Mountain Divide, LLC	89.75%	71.7940%	6-Jul-13	Producing
Olson 2-11S-1H	Mountain Divide, LLC	70.27%	56.7990%	7-Aug-13	Producing *
Charlotte 1-12-1H	Mountain Divide, LLC	69.81%	56.3650%	31-Aug-13	Producing *

* The Olson and Charlotte well were completed subsequent to the nine months ended September 30, 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	G3 Operating, LLC	12.50%	10.0000%	4-Mar-11	Producing
Wolter	SM Energy	3.25%	2.6000%	12-Sep-11	Producing
Strahan	Hess Corporation	0.63%	0.5000%	1-Feb-11	Producing
Miller	Petro-Hunt LLC	0.79%	0.6296%	16-Nov-11	Producing
Zuma	Samson Resources Company	9.75%	7.8000%	14-Jan-12	Producing
Riva Ridge	Samson Resources Company	3.24%	2.5920%	11-Feb-12	Producing
Anton	American Eagle Energy Corp	3.38%	2.7040%	16-Jun-12	Producing
Muzzy	American Eagle Energy Corp	3.38%	2.7040%	26-Oct-12	Producing
Orville Hendrickson	Marathon Oil Corporation	12.50%	9.7500%	18-Jun-12	Producing
Panther	Zavanna, LLC	2.20%	0.2751%	11-Oct-11	Producing
Jaguar	Zavanna, LLC	1.02%	0.1269%	14-Aug-11	Producing
Leopard	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 three and nine-month period ending September 30, 2013 the Company acquired the following additional acreage in Montana and North Dakota:

Divide County, ND:

- 349.82 Acres for a total of $147,523.64
  This acreage was acquired under the spacing units the Company is currently drilling

Sheridan County, MT:

- 1,498.56 Acres for a total of $224,784.00
  This expenditure was for renewing leases in the Stateline Project.

Operations subsequent to the nine months ended September 30, 2013

Subsequent to the nine months ended September 30, 2013, the Company completed the remaining two wells on our three-well summer drilling program in the 12-Gage Prospect, Divide County, ND. Following are the results of that program to-date:

- The Olson 2-11S-1H, (the "Olson 2 Well"), the second well in the three-well summer drilling program in Mountainview's 12 Gage project in the Williston Basin, was drilled by Nabors Rig 272 to a total depth of 18,888' in 16 days. The well encountered encouraging geologic shows while drilling the lateral of 10,168', which was the longest lateral the Company has drilled to-date. The fracture stimulation conducted was a 26-stage plug and perforation program completed successfully with the well being placed on production Oct. 16, 2013. The initial 7 day average production for the Olson 2 Well, when it was still recovering frac load water, was 506 boe/d gross (284 boe/d net) of 90% oil. The 18-day average was 483 boe/d gross (271 boe/d net to the Company) of 90% oil.

- The Charlotte 1-12-1H, (the "Charlotte Well"), the Company's third Three Forks well of its summer three-well drilling program, was drilled to a total depth of 19,000' in 14 days. Mountainview successfully completed the well with a 32-stage plug and perf fracture stimulation and flowed back the well The Charlotte well is the Company's first well to be completed with a 32-stage fracture stimulation and the company still plans to meet its projected drilling and completion budget of $6.5MM on this well. The well has been placed on production with artificial lift.

Mountainview Operation/Production Update

Mountainview has now completed its second drilling program in 2013 on the 12 Gage Project. With the completion of this latest program, the Company operates 4.3 net wells (6.0 gross wells) in the project and approximately 35%-40% of the project lands are held by production. Based on field production numbers, the Company averaged 890 barrels of oil equivalent ("boe") per day ("boe/d") gross (715 boe/d net) of 90% oil for the first 15 days of October in its 12 Gage project. This does include production from all wells, as we are currently conducting 30-day tests on the Olson 2-11S-1H and Charlotte1-12-1H.

(Reported in US Dollars, unless otherwise indicated)

Overall Mountainview has seen its overall corporate production increase by 290% on both a gross and net basis since the beginning of 2013.

In addition to the substantial production increase, the Company has entered into a sales agreement for marketing its associated gas from its wells in the 12 Gage project and is working with a partner on a pipeline water disposal system.

Results of operations

	Q3 2013	Q2 2013	Q1 2013	Q4 2012
South Alberta Bakken (Bbls per day)	101	99	101	102
Williston Basin (bbls per day)	578	603	249	-
Williston Basin - non-operator (bbls per day)	42	55	56	44
Natural gas (Mcf per day)	225	309	336	337

	Q3 2012	Q2 2012	Q1 2012	Q4 2011
South Alberta Bakken (Bbls per day)	102	111	110	111
Williston Basin (bbls per day)	-	-	-	-
Williston Basin - non-operator (bbls per day)	49	45	32	-
Natural gas (Mcf per day)	335	241	29	29

Oil production increased to 721 bbl/d during Q3 2013 compared with 151 bbl/d in Q3 2012. The Company increased the oil production by the drilling and completing of four wells in the 12-Gage property located in the Williston Basin. The Company experienced a decrease in revenues from its natural gas interests as there was a decrease in production due to maintenance that was being done during the quarter. Production of natural gas in Q3 2013 was 225 Mcf/d compared with 335 Mcf/d in Q3 2012.

(Reported in US Dollars, unless otherwise indicated)

Average Realized Prices

	Q3 2013	Q2 2013	Q1 2013	Q4 2012
Average benchmark prices				
Oil - WTI crude oil USD ($/Bbl)	105.84	94.22	94.37	87.96
Oil - CHS crude oil USD ($/Bbl)	89.24	78.21	77.17	73.31
Natural gas - AECO-C Daily spot ($/mcf)	2.69	3.53	3.07	3.08
Mountainview Average Realized Prices				
South Alberta Bakken ($/Bbl)	86.72	76.30	79.72	73.94
Williston Basin ($/Bbl)	97.49	87.81	90.83	-
Natural gas ($/Mcf)	2.62	3.46	3.00	3.01

	Q3 2012	Q2 2012	Q1 2012	Q4 2011
Average benchmark prices				
Oil - WTI crude oil USD ($/Bbl)	90.83	93.48	102.89	97.82
Oil - CHS crude oil USD ($/Bbl)	74.83	73.20	85.51	83.64
Natural gas - AECO-C Daily spot ($/mcf)	2.19	1.82	2.52	3.37
Mountainview Average Realized Prices				
South Alberta Bakken ($/Bbl)	74.21	71.95	84.55	82.60
Williston Basin ($/Bbl)	-	-	-	-
Natural gas ($/Mcf)	2.12	1.75	1.52	1.78

The Company’s crude oil production consists of 46 API sweet crude oil quality in the 12-Gage Project located in Divide County, ND. The Company’s non-operated properties located in the Williston Basin also produce 46 API crude quality oil. The South Alberta Bakken properties located in Montana produce sour crude oil with gravity ranging 28 and 34 degrees API. The Company’s realized prices are reflected net of adjustments for gravity deviations from 40 degrees on the heavier crude. The Company saw an increase in sweet crude oil production due to the 12-Gage development project and other non-operated wells in the Williston Basin.

The Company realized an average oil price of $86.72/bbl in the South Alberta Bakken for the three-month period ending September 30, 2013 which is an increase from the $74.21/bbl realized for the three-month period ended September 30, 2012.

In the Williston Basin, the Company realized an average oil price of $97.49 for the three-months ended September 30, 2013. There was no production in the Williston Basin in the three months ended September 30, 2012.

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 $2.62/mcf for the three-month period ended September 30, 2013 which is an increase from the $2.12/mcf from the three-month period ended September 30 2012.

(Reported in US Dollars, unless otherwise indicated)

Revenue

	Q3 2013	Q2 2013	Q1 2013	Q4 2012
Oil sales	$ 5,926,676	$ 5,049,703	$ 1,924,319	$ 689,681
Natural gas	66,648	57,538	84,680	88,490
Gross oil and natural gas revenues	**$ 5,993,324**	**$ 5,107,241**	**$ 2,008,999**	**$ 778,171**

	Q3 2012	Q2 2012	Q1 2012	Q4 2011
Oil sales	$ 920,215	$ 716,916	$ 1,061,329	$ 928,840
Natural gas	12,342	21,813	10,057	9,562
Gross oil and natural gas revenues	**$ 932,557**	**$ 738,729**	**$ 1,071,386**	**$ 938,402**

Total oil and gas revenue during the three months ended Q3 2013 increased to $5,993,324 from the $932,557 reported in Q3 2012. The increase relates to production from the four wells drilled and completed on the 12-Gage property in Divide County, ND during the nine months ended September 30, 2013.

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 royalty expenses during the three months ended Q3 2013 were $847,848 from $52,637 in Q3 2012 due to increased sales volumes and revenues from the four wells in production on the 12-Gage property.

Production and operating Expenses

Significant components of the Company's operating expenses include well servicing, fuel and power, labour, water disposal and production taxes. The total operating expenses for the three months ended Q3 2013 increased to $1,738,209 from $396,484 in Q3 2012. Operating expenses increased due to the Company completing the four wells that were drilled on the 12-Gage property.

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
Production and operating expenditures	$ 1,738,209	$ 396,484	$ 4,393,600	$ 1,112,594
	$ 1,738,209	$ 396,484	$ 4,393,600	$ 1,112,594

(Reported in US Dollars, unless otherwise indicated)

The Company incurs significant production and operating costs for material, labour, production taxes, electrical and water disposal costs. In addition, the Company incurred significant operation costs changing the wells artificial lift system.

General and Administrative Expense

The Company recorded G&A expenses for the three months ended in Q3 2013 of $343,743 an increase of $340,606 from Q3 2012. The G&A expenses for the three and six months ended September 30, 2013 and 2012 are as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
Salaries and Wages	$ 161,503	$ 116,705	$ 439,338	$ 350,658
Accounting and Auditing	(13,519)	118,113	371,155	210,195
Travel and promotion	110,755	46,576	246,964	173,000
Legal Fees	26,412	-	160,430	-
Office expense	28,097	19,178	93,468	79,272
Insurance	14,740	12,117	44,739	36,152
Listing and filing fees	1,069	475	21,460	6,653
Director fees	6,857	-	19,817	15,534
Shareholder relations	683	7,160	17,089	91,510
Investor Relations	4,333	8,490	13,191	34,585
Transfer Agent Fees	2,813	11,792	6,828	17,168
	$ 343,743	$ 340,606	$ 1,434,479	$ 1,014,727

The large increase in accounting and auditing, salaries and wages, legal fees and office expenses relates directly to the Company expanding its operations.

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 months ended Q3 2013 $136,475 and $Nil of share-based compensation.

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 months ended September 30, 2013 increased to $1,496,052 from the $273,991 reported for Q3 2012. Increase in depletion, accretion and depreciation expense relates to the increase in non-operator wells, purchase of additional vehicles and the new wells drilled during the period in the 12-Gage Project in Divide County, ND.

Impairment of Oil and Natural Gas Properties

At September 30, 2013, 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 there was no impairment on the oil and gas properties. The recoverable amount is 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 September 30, 2013, the Company, had capitalized interest of $762,585 and $Nil for the same period in 2012 in addition to interest expense of $1,845,541 and $323,749, respectively. During the prior year, the Company capitalized interest related to the 12-Gage property development. Interest expense during the three months ended September 30, 2013 increased as a result of the Company obtaining additional financing to expand its operations and the interest relating to the 12-Gage property.

Going Concern

These interim 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 periods ended September 30, 2013 and December 31, 2012. At September 30, 2013 and December 31, 2012, the Company had a deficit of $14,359,697 and $11,526,480 respectively and working capital (deficit) of ($15,400,932) and ($17,481,721), 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 Company'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 September 30, 2013 the Company's current assets totaled $6,850,547 , which is comprised of , among other items, cash balances totaling $2,712,220, trade receivables totaling $1,683,207, and amounts due from the Company's working interest partners totaling $2,346,206. The Company's working capital deficit as of September 30, 2013 was ($15,400,932) compared to ($17,481,721) as of December 31, 2012.

As of September 30, 2013 and December 31, 2012, the Company recorded accounts payable of $9,038,730 and $8,576,036 in addition to outstanding bank debt of $8,660,000 and $8,494,000, a convertible debenture of $2,189,550, and $2,123,947, promissory notes payable of $8,847,361 and $8,061,005, a credit facility of $28,237,163 and $1,004,308 along with long-term debt of $262,629 and $120,257 comparatively.

The Company acquired a compressor plant and equipment for consideration of $2,660,000 from another company (the "**Vendor**") owned, in part (50%), by a director and officer of the Company. The Company paid $283,000 in cash for consideration and agreed to issue a Convertible Debenture (the "**Convertible Debenture**") in the amount of $2,377,000 convertible into common shares of the Company at a price of $2.50 per share. The Convertible Debenture was later reduced by $304,946 due to costs incurred by the Vendor and paid by the Company on the Vendor's behalf prior to the transaction closing. The original maturity date of the Convertible Debenture was on or before June 1, 2013. During the quarter ended September 30, 2013 the original Convertible Debenture was cancelled and a new Convertible Debenture was signed to extend the maturity date to June 1, 2015. At September 30, 2013 the balance of the Convertible Debenture was $2,072,053 plus accrued interest of $117,497. At September 30, 2013, 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 September 30, 2013 was $8,660,000. The Credit Line is secured by the assets of the Company and guaranteed by its Chief Executive Officer and a significant shareholder of the Company. Interest is payable monthly at a variable rate of prime plus 1.25%. The minimum interest rate is 5.25%. The Line of Credit has an original due date of June 17, 2013 but the Company was granted a 6-month extension by First Interstate Bank.

On November 1, 2012, Mountain Divide, LLC ("**Mountain Divide**") entered into the Credit Facility. Mountain Divide 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 Facility. At September 30, 2013, the Company owed $28,237,163 under the Facility. During the nine months ended September 30, 2013, the Company has repaid $1,747,553 of the principal and has paid $872,885 in interest.

During the nine months ended September 30, 2013, the Company increased the borrowing base by $17.4 million to fund the next three well drill program. In addition the Company incurred fees of $217,500 representing 1.25% of the borrowing base and paid $5,000 in reimbursed expenses to the lender. In addition the Company paid or accrued $696,000 for a 4% finder's fee. The finder's fee is payable at a rate of 4% based on each increase in the financing and up to the total amount available of $75.0 million.

The Company has various vehicle loans outstanding at September 30, 2013 and December 31, 2012 of $353,893 and $179,032, respectively. The current portion of vehicle loans at September 30, 2013 and December 31, 2012 is $91,264 and $58,775. The loans vary from 0% interest to 4% and will be repaid after 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 was originally due and payable on or before May 30, 2014. During the period one of the major shareholders signed a new promissory note to extend the maturity date to May 30, 2015. The interest on the promissory notes is still payable quarterly. During 2012 the Company paid interest of $209,178 on two of the Notes in addition to $150,000 in principle on one of the promissory notes. Interest accrued during 2012 was $211,005. During the period ended September 30, 2013, the balance due on the promissory notes was $7,850,000 plus accrued interest of $740,739.

The Company entered into two promissory notes payable with one major shareholder and with a Company partially owned by an officer and director of the Company each for $125,000 (total $250,000), bearing interest at 5% per annum. The principal is due March 12, 2015. During the period ended September 30, 2013 the Company accrued interest of $6,884.

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

Net Loss

The Company reported a net loss in Q3 2013 of $387,114 or $0.00 per common share. The loss relates to a significant increase in production and operating expenditures, depletion, accretion and deprecation and finance costs. The Company's net loss is offset by a significant increase in revenue in Q3 2013 of $5,145,950 compared to Q3 2012 of $959,243. The Company's net loss for the three months ended Q3 2012 was $428,315 or $0.00 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-V under the trading symbol MVW.

Related Party Transactions

During the nine months ended September 30, 2013 the Company paid or accrued $4,328,845 (September 30, 2012 - $Nil) to three companies owned by one of its major shareholders for services provided in the drilling of the wells in the 12-Gage Property. These services are provided at fair market value.

During the nine months ended September 30, 2013, the Company had a related party payable of $829,154, plus accrued interest of $17,303 (September 30, 2012 - $Nil) that was due to one of its major shareholders.

During the nine months ended September 30, 2013, the Company had a joint interest receivable of $910,087 (September 30, 2012 - $Nil) from two companies owned by two of its major shareholders. The companies are participants in certain joint venture activities based on normal industry terms and agreements

Segment Information

Operating Segments

The Company has one reportable segment, oil and natural gas exploration and production, as determined in accordance with authoritative guidance regarding disclosure about segments of an enterprise and related information. All of the Company's operations are located in the United States.

Economic dependence and major customers

In 2013, three customers, C.H.S. Inc, Sunoco Inc, and Energy West Resources Inc, accounted for approximately, 20%, 71% and 2%, respectively, of the Company's consolidated revenue. The Company enters into short term contracts with its primary customers, which are subject to periodic renewals at the discretion of both parties at market rates. Should the customer relationship with C.H.S. Inc. or Sunoco Inc. discontinue in the future, the loss of revenue might result in a material adverse effect on the Company and its going concern. For further details on the Company's assessment of its going concern basis of preparation refer to Note 1 of its interim consolidated financial statements at September 30, 2013.

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 as at September 30, 2013 and the accounting treatment of the Company's financial instruments are disclosed in the notes to the interim consolidated financial statements as at and for the three months ended September 30, 2013.

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.

(Reported in US Dollars, unless otherwise indicated)

Subsequent Events

Subsequent to September 30, 2013, the Company increased the borrowing base under the Facility by an additional $14.75 million increasing the borrowing base to $48.5 million, which will be used to fund the drilling of the Company's next two wells. The Company incurred fees of$184,375 representing 1.25% of the borrowing base plus a minimal amount of reimbursed expenses to the Lender. In addition each advance of financing is also subject to a 4% finder's fee based on the increase. Terms are the same as in Note 12.

Subsequent to September 30, 2013, the Company entered into a gas gathering, processing and purchase agreement. The agreement is effective through October 30, 2023 and states that the Company intends to sell all gas and natural gas liquids to the buyer utilizing the facilities owned and operated by the buyer. Gathering, compression and treating fees will be deducted from the sales revenue. As consideration for processing services on the gas and treatment of inferior liquids provided to the Company the buyer shall retain 25% of the total natural gas liquids and inferior liquids revenue allocated to the Company' gas sold. If in any month the total fees owed by the Company are in excess of the proceeds received, the Company is only required to pay fees to the extent of proceeds received. Any differences between the total fees owed for a particular month and fees paid will be accrued as a liability and offset against future revenue by the Buyer. In any month that a repayment is made on past shortages accrued by the Company, the Company will still receive a minimum of 25% of the proceeds for that month. Any differences accrued that have not been repaid fully by the 12th month following the initial occurrence of the difference of fees owed versus fees paid shall be forgiven by the buyer and the Company shall have no further obligation.

Subsequent to September 30, 2013, the Company entered into a drilling contract to drill the first two wells in the winter drilling program and an optional contract extension for a third well.

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

(Reported in US Dollars, unless otherwise indicated)

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 Canadian 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 purposes 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 generally accepted accounting principles.

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 Mountainview at this time.

(Reported in US Dollars, unless otherwise indicated)

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 the Company's board-approved Risk Management and Counterparty Credit Policy and risk management programs. Issues affecting, or with the potential to affect, the Company's 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.

Non-IFRS Measures

EBITDA (Earnings before Interest Taxes Depreciation and Amortization) is calculated by adding finance costs, and depreciation to net earnings. Adding back non-operating expenses allows management to consistently compare periods by removing changes in tax rates, long-term assets and financing costs.

	Three Months Ended September 30		Nine Months Ended September 30	
	2013	2012	2013	2012
Net loss	$ (387,114)	$ (428,315)	$ (2,833,217)	$ (1,052,633)
Finance costs	1,845,541	323,749	3,739,924	413,073
Depletion, accretion and depreciation	1,496,052	273,991	4,227,829	795,293
EBITDA	$ 2,954,479	$ 169,425	$ 5,134,536	$ 155,733

(Reported in US Dollars, unless otherwise indicated)

Summary of Quarterly Results

	Q3 2013	Q2 2013	Q1 2013	Q4 2012
Net Revenue	$ 5,145,950	$ 4,307,186	$ 1,746,674	$ 732,602
Net Income (Loss)	$ (387,114)	$ (1,065,275)	$ (1,475,284)	$ (7,339,991)
Income (Loss) per Share - Basic	$ (0.00)	$ (0.01)	$ (0.02)	$ (0.10)
Income (Loss) per Share - Diluted	$ (0.00)	$ (0.01)	$ (0.02)	$ (0.10)
Total Assets	$ 74,264,814	$ 67,252,582	$ 65,036,162	$ 49,055,600
Total Liabilities	$ 56,315,452	$ 49,052,580	$ 46,183,923	$ 28,823,571

	Q3 2012	Q2 2012	Q1 2012	Q4 2011
Net Revenue	$ 959,243	$ 704,659	$ 1,011,233	$ 994,900
Net Income (Loss)	$ (428,315)	$ (366,292)	$ (262,305)	$ (611,520)
Income (Loss) per Share - Basic	$ (0.00)	$ (0.01)	$ (0.00)	$ (0.01)
Income (Loss) per Share - Diluted	$ (0.00)	$ (0.01)	$ (0.00)	$ (0.01)
Total Assets	$ 49,359,566	$ 47,945,130	$ 21,248,818	$ 19,151,591
Total Liabilities	$ 21,926,374	$ 20,083,623	$ 4,879,397	$ 2,519,865

(Reported in US Dollars, unless otherwise indicated)

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