MOUNTAINVIEW ENERGY LTD.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2009 and 2008

US Funds

PRICEWATERHOUSECOOPERS

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Auditors' Report

To the Shareholders of Mountainview Energy Ltd.

We have audited the consolidated balance sheets of Mountainview Energy Ltd (the "Company") as at December 31, 2009 and 2008 and the consolidated statement of income (loss) and comprehensive income (loss) and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and 2008 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Signed *PricewaterhouseCoopers LLP*

Chartered Accountants
Vancouver, British Columbia
April 30, 2010

Mountainview Energy Ltd. Statement 1

Consolidated Balance Sheets

As at December 31
US Funds

ASSETS		**2009**		2008
Current				
Cash and cash equivalents	**$**	**353,506**	$	644,464
Short-term investments *(Note 3)*		**203,805**		400,000
Accounts receivable - trade		**251,261**		322,485
Inventory		**8,017**		4,999
		816,589		1,371,948
Property, Plant and Equipment *(Note 7)*		**254,380**		191,358
Petroleum and Natural Gas Interests *(Note 4)*		**3,492,536**		3,402,475
Reclamation Bond *(Note 4b)*		**110,883**		106,710
	$	**4,674,388**	$	5,072,491
LIABILITIES				
Current				
Accounts payable and accrued liabilities – trade *(Note 5)*	**$**	**1,235,210**	$	1,001,089
Current portion of long-term debt *(Note 8)*		**24,408**		-
Income tax payable *(Note 12)*		**64,571**		532,757
		1,324,189		1,533,846
Long-Term Debt *(Note 8)*		**85,993**		-
Asset Retirement Obligation *(Note 6)*		**271,761**		243,053
Future Income Tax Payable *(Note 13)*		**161,438**		172,893
		1,843,381		1,949,792
SHAREHOLDERS' EQUITY				
Share Capital *(Note 9)*		**1,071,140**		1,071,140
Contributed Surplus *(Note 10)*		**212,930**		212,930
Retained Earnings –*Statement 2*		**1,546,937**		1,838,629
		2,831,007		3,122,699
	$	**4,674,388**	$	5,072,491

Nature of Business *(Note 1)*

Measurement Uncertainty *(Note 5)*

Commitments *(Note 8b)*

Subsequent Event *(Note 16)*

ON BEHALF OF THE BOARD:

"Patrick V. Montalban" , Director

"Bruce P. Young" , Director

- See Accompanying Notes -

Mountainview Energy Ltd. <u>Statement 2</u>

Consolidated Statements of Income (Loss) and Comprehensive Income (Loss) and Retained Earnings

For the Years Ended December 31

US Funds

	2009	2008
Revenue		
Gross sales	**$ 2,357,475**	$ 4,151,733
Less royalties	**(338,067)**	(595,147)
	2,019,408	3,556,586
Cost of Sales		
Inventory - Beginning of year	**4,999**	7,218
Depletion, accretion and amortization	**430,578**	408,998
Production taxes	**232,777**	399,071
Labour	**199,357**	149,027
Repairs and maintenance	**181,119**	146,830
Utilities	**135,596**	129,909
Materials	**124,693**	76,236
Vehicle	**70,817**	84,319
Amortization - Equipment	**68,588**	72,901
Miscellaneous production costs	**31,269**	21,266
Engineering	**17,034**	12,323
Property taxes	**4,831**	4,631
Insurance	**3,598**	3,598
Inventory - End of year	**(8,017)**	(4,999)
	1,497,239	1,511,328
Gross Profit *(2009 –25.86%; 2008 – 57.51%)*	**522,169**	2,045,258
General and Administrative Expenses *(Schedule)*	**(684,535)**	(836,644)
Income (loss) before the Undernoted	**(162,366)**	1,208,614
Other Income (Expenses)		
Interest income and expense	**11,650**	10,340
Write-down of Tie Creek Prospect *(Note 4d)*	**(243,459)**	-
Income (Loss) Before Income Taxes	**(394,175)**	1,218,954
Recovery (Provision) for Income Tax – Current *(Note 12)*	**91,028**	(528,612)
Recovery (Provision) for Income Tax – Future *(Note 13)*	**11,455**	(31,893)
	102,483	(560,505)
Net Income (Loss) and Comprehensive Income (Loss) for the Year	**(291,692)**	658,449
Retained Earnings - Beginning of year	**1,838,629**	1,180,180
Retained Earnings - End of Year	**$ 1,546,937**	$ 1,838,629
Income (Loss) per Share – Basic and Fully Diluted	**$ (0.03)**	$ 0.07
Weighted Average Number of Common Shares Outstanding - Basic & Fully Diluted	**9,766,850**	9,766,850

- See Accompanying Notes -

Mountainview Energy Ltd. Statement 3

Consolidated Statements of Cash Flows

For the Years Ended December 31
US Funds

Cash Resources Provided By (Used In)		**2009**		2008
Operating Activities				
Cash receipts from customers	**$**	**2,249,506**	$	3,855,836
Cost of sales		**(928,919)**		(1,049,418)
Cash paid to suppliers and employees		**(678,282)**		(653,078)
Income tax paid		**(377,158)**		(211,156)
Interest income and expense		**11,650**		10,340
		276,797		1,952,524
Investing Activities				
Cash paid to suppliers of petroleum and natural gas interests		**(523,182)**		(1,613,518)
Cash paid to suppliers of property, plant and equipment		**(134,172)**		(30,863)
		(657,354)		(1,644,381)
Financing Activities				
Short-term Investments		**200,000**		(400,000)
Long-term debt		**(110,401)**		-
		89,599		(400,000)
Net Decrease in Cash and Cash Equivalents		**(290,958)**		(91,857)
Cash position - Beginning of year		**644,464**		736,321
Cash Position - End of Year	**$**	**353,506**	$	644,464

Supplemental Schedule of Non-Cash Transactions:				
Amortization	**$**	**71,151**	$	75,397
Depletion, accretion and amortization	**$**	**430,578**	$	408,998
Foreign exchange (gain) loss	**$**	**6,830**	$	(3,700)
Petroleum and natural gas interests costs included in accounts payable	**$**	**3,247**	$	44,832
Property, plant and equipment costs included in accounts payable	**$**	**-**	$	1,469
Provision (Recovery) for income tax - current	**$**	**(91,028)**	$	528,612
Provision (Recovery) for income tax - future	**$**	**(11,455)**	$	31,893
Write-down of Tie Creek Prospect	**$**	**243,459**	$	-

1. Nature of Business

The Company was incorporated on May 31, 2000 in the province of British Columbia. The Company is a Tier 2 issuer on the TSX-V and is an operating oil and gas company. All revenues are from oil and gas extraction in the state of Montana, USA.

2. Accounting Policies

Basis of Consolidation

These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and include the accounts of the Company and its wholly owned subsidiary, Mountain View Energy, Inc., incorporated in Montana, USA.

All significant inter-company transactions and balances have been eliminated.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand, term deposits and short term highly liquid investments with the original term to maturity of three months or less, which are readily convertible to known amounts of cash and which, in the opinion of management, are subject to an insignificant risk of changes in value.

Inventory

Inventory is recorded at the lower of cost or net realizable value. Net realizable value is the estimated selling price in the ordinary course of business less the estimated cost of completion and the estimated cost necessary to perform the sale. Cost of oil and gas is determined on a first in, first out basis.

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas operations, whereby all costs of exploring for and developing oil and gas reserves are capitalized and accumulated in cost centres established on a country-by-country basis. Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells, interest costs on significant investments in unproved properties and major development projects and overhead charges directly related to acquisition, exploration and development activities, less any government incentives relating thereto.

The costs related to each cost centre from which there is production, together with the costs of production equipment, are depleted and amortized on the unit-of-production method based on the estimated gross proved reserves of each country. Oil and natural gas reserves and production are converted into equivalent units based upon estimated relative energy content. Costs of acquiring and evaluating significant unproved properties are initially excluded from depletion calculations. These unevaluated properties are assessed periodically to ascertain whether impairment in value has occurred. When proved reserves are assigned or the value of the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion.

Oil and Gas Properties – *Continued*

Impairment is determined when the carrying amount of property and equipment exceeds the sum of the undiscounted cash flows expected to result from the Company's proved reserves (determined pursuant to evaluation by independent engineers as dictated by National Instrument 51-101), based on future pricing. If the carrying value is impaired, the amount of impairment is measured by comparing the carrying amounts of property and equipment to an amount equal to the estimated net present value of future cash flows from proved plus probable reserves. This calculation incorporates risks and uncertainties in the expected future cash flows that are discounted using a risk-free rate. Any excess carrying value above the net present value of the future cash flows would be recorded as a permanent impairment and charged to earnings. The Company applies this test at least annually or more frequently as events or circumstances dictate. This impairment test is performed on both Canadian and US cost centers.

The costs (including exploratory dry holes) related to cost centres from which there has been no commercial production are not subject to depletion until commercial production commences. The capitalized costs are periodically assessed to determine whether it is likely such costs will be recovered in the future. Costs unlikely to be recovered in the future are written off. Proceeds from the sale of oil and gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would significantly alter the rate of depletion and amortization.

Management's estimates of oil and gas prices and reserves, and of asset retirement costs, are subject to certain risks and uncertainties that may affect the determination of the recoverability of the oil and gas property costs. Although management has made its best estimates of these factors, it is possible that material changes could occur which may adversely affect management's estimate of the net cash flows generated from its properties.

Property, Plant and Equipment

Property, plant and equipment are valued at cost less accumulated amortization. The Company provides for amortization using the declining balance method as follows:

i) Computer equipment – 30%
ii) Vehicle – 30%
iii) Field equipment – 30%

Share Capital

Share capital issued for non-monetary consideration is recorded at an amount based on fair value.

The proceeds from the issue of units is allocated between common shares and common share purchase warrants on a pro-rata basis on relative fair values as follows: the fair value of common shares is based on the market close on the date the units are issued: and the fair value of the common share purchase warrants is determined using the Black-Scholes pricing model.

Earnings per Share

Basic earnings per share is computed by dividing income available to common shareholders by the weighted average number of common shares outstanding during the period. The computation of diluted earnings per share assumes the conversion, exercise or contingent issuance of securities only when such conversion, exercise or issuance would have a dilutive effect on earnings per share. The dilutive effect of convertible securities is reflected in diluted earnings per share by application of the "if converted" method. The dilutive effect of outstanding options and warrants and their equivalents is reflected in diluted earnings per share by application of the treasury stock method.

Revenue Recognition

Revenues associated with sales of petroleum and natural gas and all other items are recorded when reserves are produced and delivered to the purchaser. Revenues are recorded gross of transportation charges incurred by the Company.

Management's Estimates

The preparation of consolidated financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reported period. Significant areas requiring the use of management estimates relate to impairment of oil and natural gas interests, determination of asset retirement obligations, royalty accrual, values of future income tax assets and liabilities and assumptions used in determining the fair value of non-cash stock-based compensation.

These estimates are limited by the availability of reliable comparable data, and the uncertainty of predications concerning future events. Accordingly, by their nature, estimates as described above are subjective

Foreign Currency Translations

The Company's functional and reporting currency is the U.S. dollar. All transactions initiated in other currencies are translated into the functional currency as follows:

i) Monetary assets and liabilities at the rate of exchange in effect at the balance sheet date,
ii) Non-monetary assets and liabilities, and equity at historical rates, and
iii) Revenue and expense items at the average rate of exchange prevailing during the period.

Gains and losses on translation are included in determining net income for the period

Stock-Based Compensation

All stock-based awards made to employees and non-employees are measured and recognized using a fair value based method. For employees, the fair value of the options is measured at the date of the grant. For non-employees, the fair value of the options is measured on the earlier of the date at which the counterparty performance is complete or the date the performance commitment is reached or the date at which the equity instruments are granted if they are fully vested and non-forfeitable. For employees and non-employees, the fair value of the options is accrued and charged to operations, with the offsetting credit to contributed surplus, on a straight-line basis over the vesting period. If and when the stock options are ultimately exercised, the applicable amounts of contributed surplus are transferred to share capital.

Impairment of Long-lived Assets

Management reviews property, plant and equipment with finite useful lives whenever events of changes in circumstances indicate that an impairment may have occurred. Recoverability is assessed by management comparing the carrying amount to the estimated future net cash flows the assets are expected to generate. Where the carrying value exceeds estimated net cash flows, the assets are written down to their estimated fair value.

Asset Retirement Obligations

The Company recognizes the estimated liability associated with an asset retirement obligation (“ARO”) in the financial statements at the time the asset is acquired and the liability is incurred. The estimated fair value of the ARO liability is recorded as a long term liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a unit-of-production method over the life of the proved reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. The ARO can also increase or decrease due to changes in the estimates of timing of cash flows or changes in the original estimated undiscounted cost. Actual costs incurred upon settlement of the ARO are charged against the ARO to the extent of the liability recorded. Differences between the actual costs incurred and the fair value of the liability recorded are recognized in earnings in the period incurred.

Leases

Leases are classified as capital or operating leases. A lease that transfers substantially all the benefits and risks incident to the ownership of property is classified as a capital lease. All others leases are accounted for as operating leases whereby lease payments are expensed. Gains and losses arising on the sale and leaseback transactions, when the leaseback is classified as a capital lease, are deferred and amortized in proportion to the amortization of he leased asset. Lease inducements received are recorded as a deferred credit and amortized as a reduction of lease expense over the term of the lease.

Income Taxes

The asset and liability method is used for determining future income taxes. Under the asset and liability method, the change in the net future tax asset or liability is included in income. The income tax effects of temporary differences in the time when income and expenses are recognized in accordance with Company accounting practices and the time they are recognized for income tax purposes are reflected as future income tax assets or liabilities. Future income tax assets and liabilities are measured using statutory rates that are expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled.

Joint Interests

A portion of the Company’s exploration, development and production activities is conducted jointly with others. Accordingly, these financial statements reflect only the Company’s proportionate interest in such activities.

Financial Instruments

The Company classifies its financial assets as either held-for-trading, available-for-sale, or loans and receivables. Financial liabilities are classified as either held-for-trading, or other financial liabilities. Held-for-trading financial assets and liabilities are recorded at fair value as determined by active market prices and valuation models, as appropriate. Changes in fair value of held-for-trading financial instruments are recorded in net earnings. Available-for-sale financial assets are recorded at fair value as determined by active market prices. Unrealized gains and losses on available-for-sale investments are recognized in other comprehensive income. If a decline in fair value is deemed to be other-than temporary, the unrealized loss is recognized in net earnings. Investments in equity instruments that do not have an active quoted market price are measured at cost. Loans and receivables and other financial liabilities are recorded initially at fair value, net of transaction costs incurred, and subsequently at amortized cost using the effective interest rate method.

New Accounting Pronouncements

In February 2008, the AcSB issued Handbook Section 3064, Goodwill and Intangible Assets and amended Section 1000, Financial Statement Concepts clarifying the criteria for the recognition of assets, intangible assets and internally developed intangible assets. Items that no longer meet the definition of an asset are no longer recognized with assets. This standard also provides guidance for the treatment of pre-production and start-up costs and requires that these be expensed as incurred. The standard is effective for fiscal years beginning on or after October 1, 2008. The Company adopted this new section on January 1, 2009 with no impact on its consolidated financial statements.

In January 2009, the CICA issued EIC-173, "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". The EIC provides guidance on how to account for the credit risk of an entity and counterparty when determining the fair value of financial assets and financial liabilities, including derivative instruments. The Company immediately adopted the EIC, with no impact on its consolidated financial statements.

In June 2009, the CICA Handbook Section 3862, Financial Instruments – Disclosures, was amended to require disclosures about the inputs to fair value measurements, including their classification within a hierarchy that prioritizes the inputs to fair value measurement. The three levels of the fair value hierarchy are:

Level 1 – Unadjusted quoted prices in active markets for identical assets or liabilities;
Level 2 – Inputs other than quoted prices that are observable for the asset or liability either directly or indirectly; and
Level 3 – Inputs that are not based on observable market data

The Company immediately adopted this amended standard and the required disclosures are included in Note 14.

Future Canadian Accounting Pronouncements

Business Combinations (Section 1582)

In January 2009, the CICA issued Handbook Section 1582, "Business Combinations", which requires that all assets and liabilities of an acquired business be recorded at fair value at acquisition. Obligations for contingent considerations and contingencies will also be recorded at fair value at the acquisition date. The standard also states that acquisition-related costs will be expensed as incurred and that restructuring charges will be expensed in the period after the acquisition date. The Section applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period on or after January 1, 2011. The Company has early adopted this Standard effective January 1, 2010 for the fiscal year ending December 31, 2010. There was no material impact on the consolidated financial statements as a result of this adoption.

Consolidations (Section 1601) and Non-Controlling Interest (Section 1602)

In January 2009, the CICA issued Handbook Section 1601, "Consolidations" ("CICA 1601"), and Section 1602, "Non-Controlling Interests" (CICA 1602"). CICA 1601 establishes standards for preparing consolidated financial statements and CICA 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. These standards apply to interim and annual consolidated financial statements relating to fiscal years beginning on or after January 1, 2011. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The Company has early adopted this Standard effective January 1, 2010 for the fiscal year ending December 31, 2010. There was no material impact on the consolidated financial statements as a result of this adoption.

3. Short-term Investments

Short-term investments at December 31, 2009 consist of the following:

Type of Investment	Face Value	Annual Interest Rate	Maturity Date
Term deposit	$ 100,000	1.70%	September 25, 2010
Term deposit	$ 100,000	1.75%	December 15, 2010
	$ 200,000		

At December 31, 2008 the Company had short-term investments of $400,000.

4. Petroleum and Natural Gas Interests

a) Details of cumulative expenditures are as follows:

Proved and Producing		**2009**		2008
Red Creek Unit, Montana, USA:				
Purchase price	**$**	**475,000**	$	475,000
Engineering reports		**22,968**		22,968
Legal and other costs (Title opinions and professional fees)		**105,525**		105,525
Other capitalized costs		**3,600,898**		3,202,418
Asset retirement cost		**176,323**		167,785
Accumulated amortization and depletion		**(1,730,541)**		(1,320,133)
	$	**2,650,173**	$	2,653,563
Lake Frances, Montana, USA				
Other capitalized costs	**$**	**758,430**	$	464,512
Lease rentals		**83,933**		82,119
	$	**842,363**	$	546,631
Unproved				
Tie Creek Prospect, Montana, USA:				
Purchase price	**$**	**31,250**	$	31,250
Lease rentals		**199,128**		157,950
Other capitalized costs		**13,081**		13,081
	$	**243,459**	$	202,281
Write-down		**(243,459)**		-
	$	**-**	$	202,281
Total petroleum and natural gas interests	**$**	**3,492,536**	$	3,402,475

4. Petroleum and Natural Gas Interests - *Continued*

b) The Company is required by the State of Montana to deposit monies into a reclamation bond. The bond is refundable at the time that the Company performs the site restoration of the wells that are dry or are no longer in use. The amount of the bond is $110,883 (2008 - $106,710), which includes accrued interest of $30,883 (2008 - $26,710).

c) During the prior year the Company entered into an agreement to acquire a 25% working interest in four wells that were drilled on the Lake Frances property in Pondera County, Montana. During the current year, the Company entered into agreements to acquire a 25% working interest in two additional wells and a 50% working interest in one well. To participate in the drilling of these wells the Company paid or accrued costs of $274,021 (2008 - $254,696) as their share of costs to a company with a director and officer in common.

d) The costs related to the unproved properties have been excluded from the depletion calculation. The Company considered whether there were any events or circumstances indicating impairment of its capitalized assets at December 31, 2009 and determined that a write-down of $243,459 of the capitalized costs that related to unproved properties was required (2008 - $nil write-down).

e) The following table outlines the benchmark prices used in the impairment test at December 31, 2009:

Year	Oil Price (1)
2009	$ 61.78
2010	74.40
2011	77.40
2012	80.50
2013(3)	83.72

(1) Price based upon future forecast price for AECO "C" – (1000BTU/SCF) – prices have been adjusted herein for quality and transportation.
(2) Prices based upon future forecast price for WTI – (40 API rating) – prices have been adjusted herein for quality and transportation.
(3) Prices escalated at a rate of 3.0 percent per annum to thereafter.

5. Measurement Uncertainty

The company is obliged to pay royalties on its Red Creek and Lake Frances properties. In addition to the royalties paid to known parties, management has estimated an accrual for royalties potentially owing to other unidentified parties that may be entitled to royalty payments from these properties. The estimation of these obligations is dependent on the best information available to management of the royalty rates applicable on each tract of land where the Company has producing wells. Included in accounts payable and accrued liabilities is $972,319 (2008- $796,669) accrued royalties. The determination of prior and current royalties is a complex matter and management is in the process of having a legal search and opinion prepared to determine the royalties due. The amount, as determined by the legal search, may be materially different from the amount the Company has estimated for accrued royalties and there may be a significant impact on net income in the year any adjustment is made.

6. Asset Retirement Obligation

The asset retirement obligations for the years ended December 31, 2009 and 2008 are as follows:

		2009		2008
Asset retirement obligation at the beginning of the year	**$**	**243,053**	$	204,436
Net present value of new obligations during the year		**13,183**		-
Accretion expense		**20,170**		19,041
Revision in estimated cash flows on existing obligations		**(4,645)**		19,576
Asset retirement obligation at the end of the year	**$**	**271,761**	$	243,053

The Company has calculated the fair value of the asset retirement obligation using a discount rate of 4.75% to 8.5% and an inflation rate of 1.5%. The estimated total future undiscounted cash flows to settle the asset retirement obligations are $492,026 (2008 - $487,500) and are expected to be incurred over a period of approximately 5 to 18 years.

7. Property, Plant and Equipment

			2009			2008
	Cost $	Accumulated Amortization $	Net Book Value $	Cost $	Accumulated Amortization $	Net Book Value $
Office furniture equipment	**21,476**	**13,509**	**7,967**	17,504	10,946	6,558
Field equipment	**302,581**	**192,981**	**109,600**	320,131	151,366	168,765
Vehicles **	**200,408**	**63,595**	**136,813**	52,657	36,622	16,035
	524,465	**270,085**	**254,380**	390,292	198,934	191,358

** Included in vehicles is the cost of capital leases of $147,750 (2008 - $Nil) and accumulated amortization of $22,163 (2008 - $Nil).

8. Long-Term Debt

a) The Company has long-term debt as at December 31, 2009 of $110,401 (2008 - $Nil) relating to the purchase of vehicles for the Company. The current portion relating to the long-term debt is $24,408 (2008 $Nil). The interest rates on the long-term debt range from 1.9% -6% and are fixed for the duration of the loans. These loans are securitized on the assets themselves.

b) Commitments

2010	$ 24,408
2011	$ 25,977
2012	$ 26,882
2013	$ 20,334
2014	$ 12,800

9. Share Capital

a) Authorized:

100,000,000 common shares without par value
100,000,000 preference shares without par value

b) Issued and fully paid:

	Common Shares		Amount	
	2009	2008	**2009**	2008
Balance	**9,766,850**	9,766,850	**$ 1,071,140**	$ 1,071,140

No preference shares have been issued.

c) As at December 31, 2009 and 2008, there were no share purchase warrants outstanding.

d) Share Purchase Options

The Company has established a share purchase option plan which authorizes the board of directors to grant options for the purchase of up to 10% of the issued and outstanding common shares. Options granted must be exercised no later than five years from the date of grant or such lesser period as determined by the Company's board of directors.

The Company's stock option activity at December 31, 2009 is as follows:

Balance at December 31, 2008	Granted	Exercised	Expired	Balance at December 31, 2009	Exercise Price	Expiry Date
775,000	-	-	-	775,000	$0.24	June 17, 2013

As at December 31, 2009, a total of 775,000 of outstanding options have vested.

The Company's stock option activity at December 31, 2008 is as follows:

Balance at December 31, 2007	Granted	Exercised	Expired	Balance at December 31, 2008	Exercise Price	Expiry Date
-	775,000	-	-	775,000	$0.24	June 17, 2013

As at December 31, 2008, a total of 775,000 of outstanding options have vested.

9. Share Capital - *Continued*

e) Stock-based Compensation

During the year ended December 31, 2009, the Company granted no stock options and did not incur any stock based compensation expense.

During the year ended December 31, 2008 the Company granted 775,000 stock options to its employees with an exercise price of $0.24 per share. All of the options vested immediately. For the year ended December 31, 2009, the Company recorded $212,930 of stock based compensation.

The fair value of each option granted was estimated using an option-pricing model with the following weighted average assumptions:

	2008
Expected dividend yield	0.0%
Stock price volatility	122.41%
Risk free interest rate	3.37%
Expected life of options	5 years

Option pricing models require the input of highly subjective assumptions including the expected price volatility. Changes in the subjective input assumptions can materially affect the fair value estimate, and therefore the existing models do not necessarily provide a reliable single measure of the fair value of the Company's stock options.

10. Contributed Surplus

The Company's contributed surplus as at December 31, 2009 and the changes for the year ended on that date are as follows:

Balance, December 31, 2009 and 2008	$	212,930

11. Related Party Transactions

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

a) During the year, wages and benefits of $160,880 (2008 - $157,600) were paid to directors and officers of the Company.

b) During the year, investor relation fees of $31,536 (2008 - $19,595) were paid to a relative of a director and officer of the Company.

c) During the year, director fees of $10,500 (2008 - $12,000) were paid to directors of the Company.

The above transactions, occurring in the normal course of operations, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

12. Income Taxes

Details of income taxes for the year are as follows:

	2009	2008
Net income (loss) before income taxes	**$ (394,175)**	$ 1,218,954
Income tax at statutory rates	**30.00%**	31.00%
Expected income tax expense	**(118,252)**	377,876
Non-deductible items and other	**56,595**	75,729
Difference in foreign tax rates	**(40,826)**	106,900
Income tax (recovery) expense	**$ (102,483)**	$ 560,505

Details of income tax expense are as follows:

	2009	2008
Current income tax expense	**$ (91,028)**	$ 528,612
Future income tax expense	**(11,455)**	31,893
Total income tax expense	**$ (102,483)**	$ 560,505

13. Future Income Tax

The significant components of the Company's future income tax liabilities applying substantially US enacted corporate tax rates of 38% are as follows:

	2009	2008
Petroleum and Natural Gas Interests	**$ 161,438**	$ 101,679
Property, plant and equipment	**-**	71,214
Future Tax Liability	**$ 161,438**	$ 172,893

14. Capital Risk Management

The Company's objectives when managing capital are to safeguard its ability to continue as a going concern, to provide an adequate return to shareholders, while satisfying other stakeholders, and to support any growth plans.

In the management of its capital, the Company includes the components of shareholders' equity and long-term debt.

The Company's objectives when managing capital are to:

i) Continue the development of its Petroleum and Natural Gas Interests
ii) Support any expansion plans; and
iii) Maintain a capital structure which optimizes the cost of capital at an acceptable risk.

As at December 31, 2009, the Company had no bank indebtedness and long-term debt of $110,401.

As at December 31, 2008, the Company had no bank indebtedness and no long-term debt.

There were no changes in the Company's approach to capital management during the year ended December 31, 2009 compared to the year ended December 31, 2008. The Company is not subject to externally imposed capital requirements.

15. Financial Instruments

a) Categories of financial assets and liabilities

As at December 31, 2009, the carrying and fair value amounts of the Company's financial instruments are the same. The carrying value of the Company's financial instruments is classified into the following categories:

		December 31, 2009		December 31, 2008
Held for trading	$	**557,311**	$	1,044,464
Loans and receivables	$	**251,260**	$	322,485
Held to maturity	$	**110,883**	$	106,710
Other financial liabilities	$	**1,410,182**	$	1,001,089

b) Classification of Financial Instruments

The Company designated its cash and cash equivalents and short-term investments as held-for-trading, and are measured using level 2 fair value measures (in accordance with the CICA Handbook Section 3862). GST and other receivables have been designated as loans and receivables, which are measured at amortized cost. The reclamation bond is designated at held-to-maturity and is measured at amortized cost. Accounts payable and accrued liabilities and long-term debt are classified as other financial liabilities, which are measured at amortized cost.

15. Financial Instruments – *Continued*

c) Credit Risk

The Company's trade accounts receivable is comprised of oil and gas revenue receivable and this amount is due from one specific entity. Therefore, the collectability is dependent upon the general economic conditions of the purchaser. The receivable amount is not collateralized and to date the Company has never recorded any bad debts.

The maximum exposure to credit risk is represented by the carrying amount of cash and equivalents, short term investments, and accounts receivable in the balance sheet. The Company's cash and equivalents and short term investments are deposited with a US regional bank.

d) Foreign Currency Exchange Risk

The majority of the Company's operations are conducted in U.S. dollars. The Company is exposed to foreign currency fluctuations to the extent cash, GST receivable and accounts payable and accrued liabilities of the Company not denominated in US dollars.

At December 31, 2009, the Company had the following assets and liabilities dominated in Canadian dollars.

		December 31, 2009		December 31, 2008
Cash	$	**4,559**	$	3,573
GST receivable	$	**6,933**	$	11,023
Accounts payable and accrued liabilities	$	**93,371**	$	82,734

e) Commodity Price Risk

The Company is exposed to market risk and commodity price risk. Based on these commodity price exposures at December 31, 2009 a $10 decrease or increase in the average price of oil would result in a decrease or increase of gross revenues of approximately $445,000. Declines in the market price of commodities, most significantly oil and gas, can not only adversely affect operating results, but may also affect the Company's ability to raise additional capital. As at the balance sheet date, the Company did not have any commodity price risk contracts in place to mitigate these risks.

f) Interest Rate Risk

The Company's bank accounts earn interest income at variable rates. The Company's future interest income is exposed to changes in short-term rates. The Company is not exposed to fluctuations in interest expense from the long-term debt as the rates are fixed. Fluctuations do not give rise to significant changes in income.

15. Financial Instruments – *Continued*

g) Liquidity Risk

The Company seeks to manage liquidity risk by maintaining sufficient cash and short-term investment balances for settlement of its obligations as they fall due. As at December 31, 2009, the Company had a working capital deficit of $507,600 (2008 - $161,898). Management expects to be able to satisfy this deficit, and its long term obligations, through improved cash inflows from operations based on improved oil prices in 2010 and beyond.

16. Subsequent Event

Subsequent to the year end the Company signed a letter of intent to enter into an agreement to acquire a 100% working interest of the third parties 30% interest in all wells and oil and gas leases in the Snoose Coulee Field located in Liberty County, Montana for $55,000.

Mountainview Energy Ltd. <u>Schedule</u>

Consolidated Schedule of General and Administrative Expenses

For the Years Ended December 31

US Funds

		2009		2008
General and Administrative Expenses				
Wages and benefits	**$**	**262,872**	$	245,960
Travel and promotion		**172,371**		133,612
Legal, accounting and consulting fees		**103,855**		91,054
Office supplies and utilities		**72,793**		99,460
Investor relations *(Note 10)*		**31,536**		19,595
Director fees *(Note10)*		**10,500**		12,000
Telephone		**8,275**		9,894
Listing and filing fees		**7,073**		8,223
Foreign exchange (gain) loss		**6,830**		(3,700)
Transfer agent fees		**5,867**		5,120
Amortization		**2,563**		2,496
Stock based compensation *(Notes 8 and 9)*		**-**		212,930
	$	**684,535**	$	836,644

Form 51-102F1
Management Discussion and Analysis

MOUNTAINVIEW ENERGY LTD
Fiscal Year Ended December 31, 2009

April 30, 2010

Management's discussion and analysis (MD&A) of the financial condition, results of operations and cash flows should be read in conjunction with the consolidated financial statements and the accompanying notes. This discussion and analysis is based on information available to April 30, 2010. Additional information relating to the Company is on SEDAR at www.sedar.com.

Forward Looking Statements

This report contains certain "forward-looking statements" within the meaning of such statements under applicable securities law. Forward-looking statements are frequently characterized by words such as "plan", "expect", "estimate", "believe", and other similar words, or statements that certain events or conditions "may", or "will" occur. By their nature, forward-looking statements limited to, those associated with resource definition, the possibility of project cost overruns or unanticipated costs and expenses, regulatory approvals, fluctuating oil and gas prices, and the ability to access sufficient capital to finance future development, reservoir performance and drilling results. Although the Company believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. The Company does not undertake any obligation to update publicly or to revise any of the included forward-looking statements as a result of new information, future events or otherwise, subsequent to the date of this report, except as required by law. The reader is cautioned not to place undue reliance on forward-looking statements.

Company Overview

Mountainview Energy Ltd ("Mountainview" or the "Company") is involved in the acquisition of petroleum and natural gas rights, the exploration for, and development and production of, crude oil, condensate and natural gas. The Company is listed on the TSX Venture Exchange under the symbol "MVW".

Operations and Financial Condition

Gross Revenues for the Year Ended December 31, 2009 of $2,357,475 decreased by $1,794,258 from the $4,151,733 in Gross Revenues reported for the same period in 2008 (Gross Revenues include a nominal amount of bookkeeping revenue). Also included in these figures are the Gas Revenues received for gas wells in which the Company holds a Working Interest, as later disclosed). The change in the revenues between these two periods is a direct result of the decrease in the price received per barrel of oil and a slight decrease in sales volumes. The following schedule shows a trend of increasing revenues received by the Company during the past eight quarterly periods with the exception of the 4th Quarter 2008 and 1st Quarter 2009, where there was a significant decline in pricing. The Company is currently receiving an average of approximately $65.00 per barrel.

Period	Sales Volumes (Barrels)	Average Price (US $)	Gross Oil Sales (US $)
4th Quarter 2009	11,180	65.13	728,128
3rd Quarter 2009	11,488	57.37	659,109
2nd Quarter 2009	11,115	50.05	556,040
1st Quarter 2009	10,745	33.05	354,990
4th Quarter 2008	11,527	44.50	512,965
3rd Quarter 2008	11,971	104.96	1,256,461
2nd Quarter 2008	12,148	112.12	1,362,042
1st Quarter 2008	10,419	85.00	885,649

As depicted in the foregoing schedule the average price per barrel of oil received increased by $20.63 per barrel to $65.13 for the 4th Quarter 2009 compared to the $44.50 received during the 4th Quarter 2008. The Company experienced a temporary decrease in the price received per barrel of oil during the 1st Quarter 2009 but have seen a steady increase through the 4th Quarter 2009. The Company's posting price per barrel is currently at US$71.00.

Summary of Quarterly Results

Period	Net Revenue ($)	Net Income (Loss) ($)	Income (Loss) per Share Basic ($)	Income (Loss) Per Share Diluted ($)	Total Assets ($)	Total Long-Term Liabilities ($)
4th Quarter 2009	642,433	(176,762)	(0.02)	(0.02)	4,674,388	519,192
3rd Quarter 2009	569,267	16,361	(0.00)	(0.00)	4,965,746	512,948
2nd Quarter 2009	494,577	(10,923)	(0.00)	(0.00)	4,817,063	526,629
1st Quarter 2009	313,131	(120,368)	(0.01)	(0.01)	4,680,137	425,466
4th Quarter 2008	465,070	(193,821)	(0.02)	(0.02)	5,072,491	415,946
3rd Quarter 2008	1,110,646	478,008	0.05	0.05	5,032,834	345,436
2nd Quarter 2008	1,194,389	148,520	0.02	0.02	4,489,054	345,436
1st Quarter 2008	786,481	225,742	0.02	0.02	3,742,715	345,436

Selected Annual Information

	Year ended December 31, 2009 $	Year ended December 31, 2008 $	Year ended December 31, 2007 $
Gross Revenue	**2,357,475**	**4,151,733**	**2,685,372**
Depletion, accretion and amortization	**430,578**	**408,998**	**244,620**
Interest income	**11,650**	**10,340**	**7,708**
Income (Loss) before taxes	**(394,175)**	**1,218,954**	**675,476**
Income tax (expense) recovery	**102,483**	**(560,505)**	**(275,000)**
Net income (loss) for the year	**(291,692)**	**658,449**	**400,416**
Earnings (loss) per share – basic	**(0.03)**	**0.07**	**0.04**
Earnings (loss) per share – fully diluted	**n/a**	**0.07**	**0.04**
Total Assets	**4,674,388**	**5,072,491**	**3,532,783**
Long Term Debt	**85,993**	**-**	**-**

The significant increase in gross revenues in 2008 from the years ended 2009 and 2007 relates to the price of oil being in excess of $100 per barrel.

Earnings before interest, income taxes, depletion, accretion and amortization ("EBITDA")

EBITDA is a non-GAAP measure, which is used to determine the Company's ability to generate cash flows and returns from its operating activities and is presented to be comparable to the disclosures of other iodine producers. EBITDA does not have a standardized meaning prescribed by GAAP but has been prepared on a basis consistent with the industry standard Brook Hunt definitions.

Reconciliation from net income to EBITDA for the years ended December 31, 2009, 2008 and 2007 is as follows:

	Year ended December 31, 2009 $	Year ended December 31, 2008 $	Year ended December 31, 2007 $
Net income (loss) for the year	**(291,692)**	**658,449**	**400,416**
Interest income	**(13,530)**	**(10,340)**	**(7,708)**
Depletion, accretion and amortization	**430,578**	**408,998**	**244,620**
Income taxes expense (recovery)	**(102,483)**	**560,505**	**275,000**
EBITDA	**606,257**	**1,617,612**	**912,328**

During the year ended December 31, 2009 the Company wrote-down its Tie Creek Property. The total write-down was $243,459.

Increase in the revenues for the year ended December 31, 2008 related directly to the price of oil being in excess of $100 per barrel. Depletion, accretion and amortization is based on units of production so as the Company has increased its production the depletion, accretion and amortization will continue to increase.

RED CREEK FIELD, MONTANA, USA

<u>2009 Drilling Program:</u>

There were no wells drilled in the Red Creek Field during 2009.

<u>2008 Drilling Programs</u>

A two-well drilling program was conducted during the 1st Quarter 2008 in the Red Creek Field. The two oil wells, Red Creek No. 40 and No. 41, were successfully completed and placed on production in May 2008. Mountainview owns 100% Working Interest in the Red Creek No. 40 and No. 41.

> <u>Red Creek No. 40:</u> The Red Creek No. 40 had an initial production rate of 21 barrels of oil per day and 5 barrels of water per day from the Madison/Sun River Dolomite. The producing interval in the Madison/Sun River Dolomite is 2,770' to 2,772'. There is an additional 14 feet of Upper Cut Bank Gas pay zone and 30 feet of Middle and Lower Cut Bank Oil pay zone, for a total of 44 feet that has yet to be perforated and completed

> <u>Red Creek No. 41:</u> The Red Creek No. 41 had an initial production rate of 121 barrels of oil per day and 22 barrels of water per day from the Madison/Sun River Dolomite. A two week test showed average production at 81 barrels of oil and 26 barrels of water per day. The producing interval in the Madison/Sun River Dolomite is 2,766' to 2,770'. Sample and log interpretations show the total amount of pay from 2,766' to 2,782' for a total of 16 feet of oil pay zone. There is an additional 12 feet of Upper Cut Bank Gas pay zone and 35 feet of Middle and Lower Cut Bank Oil pay zone, for a total of 47 feet that has yet to be perforated and completed.

During the 3rd Quarter 2008 another two-well drilling program was conducted in the Red Creek Field. The Red Creek No. 42 and No. 43, two oil wells, were successfully completed on placed on production during the quarter.

> <u>Red Creek No. 42:</u> The Red Creek No. 42 had an initial production rate of 18 barrels of oil per day and 5 barrels of water per day from the Madison/Sun River Dolomite. The producing interval in the Madison/Sun River Dolomite is 2,755' to 2,772'. There is an additional 26 feet of Upper Cut Bank Gas pay zone (2590' – 2616') and 16 feet of Middle and Lower Cut Bank Oil pay zone (2648'-2664'), for a total of 42 feet that has yet to be perforated and completed.

> <u>Red Creek No. 43:</u> The Red Creek No. 43 had an initial production rate of 7 barrels of oil per day and 48 barrels of water per day from the Madison/Sun River Dolomite. The producing interval in the Madison/Sun River Dolomite is 2,765' – 2778'. There is an additional 43' of Upper Cut Bank Gas pay zone (2601'-2644') and 35' feet of Middle and Lower Cut Bank Oil pay zone (2647'-2682'), for a total of 78' feet that has yet to be perforated and completed.

The two drilling programs in the Red Creek Field have enhanced the Field's production and help to maintain the Company's steady revenue stream**.** However, the amount of generated revenue is not only relative to production but also to the price received per barrel of oil.

TIE CREEK PROSPECT, MONTANA, USA

The Company acquired the Shannon River Project located in Carter County, Montana and Hardin County, South Dakota in July of 2004. Mountain View Energy, Inc, subsidiary of Mountainview Energy Ltd completed negotiations with QMAC ENERGY, INC for a sale of a 50% Working Interest in the Company's leasehold acreage in the Shannon River Project in Carter County, Montana and Harding County, South Dakota, which amounts to approximately 42,000 acres in October 2006. QMAC ENERGY, INC also shares in 50% of any on-going costs. The Company received $400,000 for the sale of this interest and will remain as the operator of these properties.

Campen Consulting, Inc completed a geological study of the acreage in the Shannon River Project in Carter County, Montana and Harding County, South Dakota, now called the Tie Creek Prospect. This study consisted of maps and cross sections of the area, which Management is in the process of analyzing for development possibilities

Due to logistics and information obtained through geologic studies, the Company has opted to dispense with any further operations in the Tie Creek Prospect and as a result incurred a write-down of $243,459 for all costs related to the property.

SOUTHWEST PONDERA PROSPECT, MONTANA, USA

Mountain View Energy, Inc., a wholly owned subsidiary of Mountainview Energy Ltd entered into a farm-out agreement with Majestic Oil & Gas, Inc on September 1, 2009, outlining parameters for Mountain View Energy, Inc to drill a test well in the NWSE-Section 33-T27N-R4W, Teton County, MT at its sole cost, risk and expense. In doing so, Mountain View Energy, Inc., would acquire 75% of the Working Interest, while Majestic Oil & Gas, Inc would retain a 25% Working Interest in any well drilled in the 40-acre tract.

Accordingly, on September 9, 2009, Mountain View Energy, Inc commenced drilling operations on the Donovan #33-3 well located in the SWNWSE – Section 33-T27N-R4W, Teton County, Montana. The well was successfully drilled and completed with an initial production of 15 barrels of oil per day with no water. The producing interval is the Madison/Sun River Dolomite with 20 feet of pay from 2,125' to 2,145'.

Due to the success of the Donovan #33-3, a second oil well was drilled in the SENWSE - Section 33-T27N-R4W, Teton County, Montana, being the Donovan #33-2. This oil well was successfully drilled and completed with an initial production of 2 barrels of oil per day.

LAKE FRANCES FIELD – PONDERA COUNTY, MONTANA, USA

<u>2009:</u>

During the 1st Quarter 2009, the Company participated in the drilling and completion of the Vandenbos #13-1 well with Altamont Oil & Gas, Inc, a Company 100% owned by Mountainview Energy Ltd's President and Chief Executive Officer. This natural gas well is located in Section 13-T29N-R5W, Pondera County, Montana and the Company paid two-thirds of the drilling and completion costs in the amount of $124,836 in order to earn a 50% Working Interest in this well.

The initial production test of the Vandenbos #13-1 well was 3.5 pounds on a 1" orifice, which is 263 MCF per day. With these results, it was determined that the Lake Frances Field extends to the northwest, proving up additional locations for drilling. The production interval on the Vandenbos #13-1 well is 2368' to 2382', with 14 feet of total pay zone. The Company has completed and is currently constructing the pipeline in order to connect the well the gathering system.

During the 2nd Quarter 2009, the Company participated in the drilling of the Jody Field #4-1A well with Altamont Oil & Gas, Inc., a Company 100% owned by Mountainview Energy Ltd's President & Chief Executive Officer. This potential oil well is located in Section 4-T29N-6W, Pondera County, Montana and the Company has committed to paying two-thirds of the drilling and completion costs in order to earn a 50% Working Interest.

Effective October 1, 2009, Mountain View Energy, Inc., the Company's wholly owned subsidiary purchased all right, title and interest in 3 natural gas wells in the Lake Frances Field from Compass Energy, Inc. The Company paid $20,000 for working interests in the Jim Powers #3 and #4 well along with the J.V. Inc. #2, as follows:

Well	Working Interest	Net Revenue Interest
Jim Powers #3	22.5%	19.4625%
Jim Powers #4	17.5%	15.1375%
J.V. Inc #2	20.51471%	17.4375%

2008:

Mountainview Energy Ltd opted to participate in the drilling and completion of two natural gas wells located in Pondera County, Montana during the 3rd Quarter 2008. In order to acquire a 25% Working Interest in these two wells, the Company paid 1/3 of the drilling and completion costs as follows:

Boucher #18-1: $54,238
Stoltz #18-1: $54,085

Following are the revenues received or accrued for these new gas wells from inception to-date. (Figures are based on the Company's Net Revenue Interest.)

	Net Volumes	**Average Price Per MCF**	**Gross Revenue**	**Share of Production Taxes**	**Share of Operating Expenses**	**Net Revenue**
B. Ag. #25-1 (Net Revenue Interest – 20%)						
4th Quarter 2009	98	1.99	195	18	1,281	(1,104)
3rd Quarter 2009	108	1.33	143	13	319	(189)
2nd Quarter 2009	112	1.52	170	16	337	(183)
1st Quarter 2009	109	2.41	265	8	450	(193)
4th Quarter						

2008	114	3.41	390	3	421	(34)
3rd Quarter 2008	118	6.04	719	5	394	320
2nd Quarter 2008	123	6.15	755	6	379	370
1st Quarter 2008	124	4.45	556	4	293	259
4th Quarter 2007	70	3.92	280	2	294	(16)

Vandenbos #19-1 (Net Revenue Interest – 20.625%)						
4th Quarter 2009	1,084	1.99	2,152	199	399	1,554
3rd Quarter 2009	1,272	1.33	1,695	157	356	1,182
2nd Quarter 2009	1,497	1.52	2,275	210	375	1,690
1st Quarter 2009	1,394	2.41	4,899	142	463	4,294
4th Quarter 2008	2,513	3.41	8,572	65	445	8,062
3rd Quarter 2008	3,150	6.04	19,335	147	432	18,756
2nd Quarter 2008	3,984	6.15	24,095	183	416	23,496
1st Quarter 2008	5,030	4.45	22,255	169	981	21,105
4th Quarter 2007	2,860	3.92	11,343	86	298	10,959

Month	**Net Volumes**	**Actual Price Per MCF**	**Gross Revenue**	**Share of Production Taxes**	**Share of Operating Expenses**	**Net Revenue**
Jim Powers #20-1 (Net Revenue Interest – 41.875%)						
4th Quarter 2009	208	1.99	408	3	798	(393)
3rd Quarter 2009	198	1.33	265	2	1,595	(1,332)
2nd Quarter 2009	175	1.52	267	2	749	(484)
1st Quarter 2009	246	2.41	608	5	926	(323)
4th Quarter 2008	423	3.41	1,444	11	1,841	(408)
3rd Quarter 2008	718	6.04	4,516	34	2,210	2,272

2nd Quarter 2008	1,916	6.15	11,487	87	890	10,510
1st Quarter 2008	448	4.98	2,229	17	-	2,212
Boucher #18-1 (Net Revenue Interest – 20.625%)						
4th Quarter 2009	359	1.99	1,059	8	231	819
3rd Quarter 2009	572	1.33	759	6	319	434
2nd Quarter 2009	734	1.52	1,116	8	337	770
1st Quarter 2009	1,135	2.41	2,769	21	426	2,322
4th Quarter 2008	1,435	3.41	4,895	37	408	4,450
3rd Quarter 2008	1,018	5.21	5,253	40	626	4,587
Stoltz #18-1 (Net Revenue Interest – 20.3125%)						
4th Quarter 2009	5	1.99	2	2	356	(354)
3rd Quarter 2009	18	1.33	26	0.18	319	(293)
2nd Quarter 2009	34	1.52	52	0.38	337	(285)
1st Quarter 2009	60	2.41	156	1	426	(271)
4th Quarter 2008	165	3.41	562	4	332	226
3rd Quarter 2008	97	5.21	499	4	268	227
Vandenbos #13-1 (Net Revenue Interest – 41.25%						
4th Quarter 2009	8,131	1.99	6,685	51	1,161	5,473
3rd Quarter 2009	3,788	1.33	5,050	38	675	4,337
2nd Quarter 2009	4,002	1.52	6,038	35	2,818	3,185
Jim Powers #3						
4th Quarter 2009	240	1.99	479	0	214	265
3rd Quarter 2009	163	1.33	213	0	0	213
Jim Powers #4						
4th Quarter 2009	184	1.99	360	0	167	193
3rd Quarter 2009	160	1.33	208	0	0	208

J.V. Inc. #2						
4th Quarter 2009	395	1.99	762	70	115	577
3rd Quarter 2009	320	1.33	408	38	0	370
Total Net Gas Revenue Received or Accrued in 2009:						$ 22,482
Total Net Revenues To-Date:						$ 129,835

Mountainview Energy Ltd is under no contractual obligation to participate in the drilling of additional wells in the Lake Frances Field.

On January 29, 2008 the Company accepted assignment of a 50% interest in three State of Montana oil and gas leases covering 389.35 Gross Acres and 194.68 Net Acres to Mountainview. The Company's net share of acquisition costs for this acreage was $12,260.

The Company's revenues have been augmented by the income generated from the natural gas wells in which Mountainview holds a working interest. The Company anticipates the receipt of additional revenues from oil produced from the Donovan #33-2 and #33-3 oil wells, as discussed above.

RESULTS OF OPERATIONS

The Company had a Net Loss from operations before taxes of $394,175 for the year ended December 31, 2009 (2008 – Net Income $1,218,954). The reason for the significant change in Net Income between the two periods is a direct result of the significant decrease in the price received per barrel.

The Company reported general and administrative expenses of $684,535 for the year ended December 31, 2009. This compares to the $836,644 reported for the same period in 2008. The decrease in expenses from the year ended December 31, 2009 compared to the same period in 2008 is due mainly to a decrease in stock-based compensation expense.

The Company recognized a current provision for Income Tax Expense (Recovery) of ($91,028) for the year ended December 31, 2009 compared to $528,612 for the same period in 2008. The Company's income tax burden will decrease in response to the decrease in taxable revenues, as a result of the decrease in the price received per barrel of oil.

The Company's Cash Position decreased during the year ended December 31, 2009 to $353,506 from the $644,464 reported for the same periods in 2008. This decrease in cash of $290,958 is a direct result of the significant decrease in the price received per barrel of oil, resulting in a decrease in revenues for the period

As depicted in the Consolidated Statement of Income (Loss), Comprehensive Income (Loss) and Retained Earnings, the major cash operating expense during the year ended December 31, 2009 was Production Taxes at $232,777. This is a considerable decrease over the $399,071 reported for the same period in 2008, and relates directly to the decrease in revenues, as a result in a decrease in the price per barrel of oil. The Company receives a "tax holiday" on new wells drilled and those placed on production after being dormant for a long period of time. This "tax holiday" consists of a significantly reduced tax rate on new production for a period of 12 consecutive months. Since the Company had two newly drilled wells on production during the period and existing shut-in wells, which were placed on production after a long period of time in prior quarters, this resulted in a large share of the oil sales for the period being taxed at a reduced rate. However, the Company is still subject to a higher tax rate, for those wells that have been in production for a longer period of time. Thus, tax rates for the current period reverted to the non-stripper rate, as implemented by the State of Montana. Normally, the wells in the Red Creek Field would be taxed at a stripper rate of 5.76%. However, if at any time during a quarterly period the West Texas Intermediary posting price for a barrel of oil exceeds $30.00, the stripper rate becomes null and void and the wells are taxed at the regular rate of 12.76%, thus leading to a higher tax liability.

Another major operating expense continues to be for utilities. This expense is comprised of charges for electricity used in operating electric motors for pumping units, injection pumps and REDA submersible pumps in the Red Creek Field. Another major expense is for materials and supplies for maintaining the production from new and existing wells. This expense will increase as the Company continues to increase its quarterly production. In addition, as the Company continues to drill new wells bringing anticipated increases in production, expenses associated with operating these wells are also expected to increase. Therefore, the Company can expect to see increases in costs for production taxes, utilities, labor, repairs and maintenance with the addition of each new well. Another major expense to note was for depletion, accretion and amortization, a non-cash item, which increased from the $408,998, reported for the year ended December 31, 2008 to the $430,578 reported for the same period in 2009.

Other than those disclosed in the financial statements, there have been no material write-offs or write-downs of assets during the year ended December 31, 2009.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires Management to make estimates and assumptions which affect the reported amount of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and revenues and expenses for the reporting period. Actual results could differ from those reported.

Related Party Transactions

As reported earlier in the Notes to Consolidated Financial Statements, the following related party transactions occurred during the nine months ended December 31, 2009.

a) During the twelve months ended December 31, 2009, wages and benefits of $160,880 were paid to directors and officers of the Company.

b) During the nine months ended December 31, 2009, investor relation fees of $31,536 were paid to a relative of a director and officer of the Company.

c) During the twelve months ended December 31, 2009, the Company paid or accrued $274,021 to a private Company, which is 100% owned by the Company's President & Chief Executive Officer for drilling and completion costs for a 50% working interest in an one oil well and one natural gas well drilled in the Lake Frances Field.

d) During the twelve months ended December 31, 2009, director fees of $10,500 were paid to directors of the Company.

e) During the twelve months ended December 31, 2009, the Company entered into a Farm-out Agreement with Majestic Oil & Gas, Inc, a U.S. Public Company, whose President & CEO is also the Company's President & CEO. This Farm-out agreement sets out the terms by which Mountain View Energy, Inc drilled a test well on a 40 acre tract located in the NWSE-Section 33-T27N-R4W, Teton County, Montana. The Company is responsible for 100% of the drilling and completion costs and will own a 75% Working Interest in the well, while Majestic Oil & Gas, Inc will retain a 25% Working Interest.

There are no material variances to-date that have impacted the Company's ability to continue its objectives as previously reported.

Financial Instruments

Mountainview's financial instruments consist of cash and cash equivalents, accounts receivable, reclamation bond, accounts payable and long-term debt. Management has reviewed all of the Company's books and records and identified the financial instruments based on an account by account review. The Company adheres to the standards set forth by the Canadian Institute of Chartered Accounts to address the criteria for recognition of financial assets and liabilities.

Categories of financial assets and liabilities

As at December 31, 2009, the carrying and fair value amounts of the Company's financial instruments are the same. The carrying value of the Company's financial instruments is classified into the following categories:

		December 31, 2009		**December 31, 2008**
Held for trading	**$**	557,311	**$**	**1,044,464**
Loans and receivables	**$**	251,260	**$**	**322,485**
Held to maturity	**$**	110,883	**$**	**106,710**
Other financial liabilities	**$**	1,410,182	**$**	**1,001,089**

Classification of Financial Instruments

The Company designated its cash and cash equivalents and short-term investments as held-for-trading. The cash equivalents and short-term investments are measured using level 2 fair value measures (in accordance with the CICA Handbook Section 3862). GST and other receivables have been designated as loans and receivables, which are measured at amortized cost. The reclamation bond is designated at held-to-maturity and is measured at amortized cost. Accounts payable and accrued liabilities are classified as other financial liabilities, which are measured at amortized cost.

The Company is exposed to market risk and commodity price risk. Based on these commodity price exposures at December 31, 2009 and the Company producing approximately 45,000 barrels of oil, a $10 decrease or increase in the average price of oil would result in a decrease or increase of gross revenues of approximately $445,000. Declines in the market price of commodities, most significantly oil and gas, can not only adversely affect operating results, but may also affect the Company's ability to raise additional capital. As at the balance sheet date, the Company did not have any commodity price risk contracts in place to mitigate these risks.

The Company's bank accounts earn interest income at variable rates. The Company's future interest income is exposed to changes in short-term rates. Fluctuations do not give rise to significant changes in income.

The Company is exposed to liquidity risk. The Company manages liquidity risk by maintaining sufficient cash and short-term investment balances for settlement of its obligations. Liquidity requirements are managed based on expected cash flow to ensure there is sufficient capital in order to meet short-term obligations

Outstanding Share Data

To-date the Company has 9,766,850 outstanding shares with Shareholder Equity of $1,071,140. As of December 31, 2009, there were outstanding options of 775,000 shares available for exercising at a price of $0.24. These options have an expiration date of June 17, 2013.

Liquidity and Solvency

The Company has a working capital deficiency for the year ended December 31, 2009 of $507,600. This is a significant decrease from the year ended December 31, 2008 in which the Company reported a working capital deficiency of $161,898. This decrease in working capital is directly related to a decrease in the Company's cash, as a result of a payment made on the Company's 2008 Income Tax Liability in the amount of $377,158 along with the outlay for drilling and completion costs associated with the 2008 Red Creek drilling program and the participation in the drilling and completion of the Vandenbos #13-1 gas well and Donovan #33-3 oil well. As earlier discussed, the Company paid approximately $124,836 in drilling and completion costs for the Vandenbos #13-1. To-date, expenses in the amount of approximately $134,000 have been incurred and paid for the drilling and completion of the Donovan #33-3 well.

The drilling and enhancement programs in the Red Creek Field and exploration project in the South Pondera Prospect are expected to contribute to the increase of the Company's cash reserves, as the price of oil continues to rebound. The price of natural gas is also rebounding, which will result in an increase in the revenues we received from the natural gas wells in which the Company owns an interest. Therefore, Management expects to be able to continue to meet its on-going obligations.

With respect to the Company's short-term liabilities, as of December 31, 2009, the Company had an obligation of $1,235,210 in Accounts Payable and $64,571 in Income Tax Payable. . Included in accounts payable and accrued liabilities is $972,319 (2008- $796,669) accrued royalties. The determination of prior and current royalties is a complex matter and management is in the process of having a legal search and opinion prepared to determine the royalties due. The amount, as determined by the legal search, may be materially different from the amount the Company has estimated for accrued royalties and there may be a significant impact on net income in the year any adjustment is made. The $161,438 for Future Income Tax Payable is an estimate of what the Company will owe for future income taxes, based on the timing differences between accounting income and taxable income. This tax will be paid when it becomes due. The $271,761 in Asset Retirement Obligation is being reported as per the rules set forth in the CICA Handbook, Section 3110, which states that the Company must recognize a legal liability for the obligations relating to the clean up and reclamation of the Red Creek Field, should the Company cease operations in the Red Creek Field.

The Company has no long-term financial liabilities or obligations other than those that are disclosed.

<u>Changes in Accounting Policies</u>

In February 2008, the AcSB issued Handbook Section 3064, Goodwill and Intangible Assets and amended Section 1000, Financial Statement Concepts clarifying the criteria for the recognition of assets, intangible assets and internally developed intangible assets. Items that no longer meet the definition of an asset are no longer recognized with assets. This standard also provides guidance for the treatment of pre-production and start-up costs and requires that these be expensed as incurred. The standard is effective for fiscal years beginning on or after October 1, 2008. The Company adopted this new section on January 1, 2009 with no impact on its consolidated financial statements.

In January 2009, the CICA issued EIC-173, "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". The EIC provides guidance on how to account for the credit risk of an entity and counterparty when determining the fair value of financial assets and financial liabilities, including derivative instruments. The Company immediately adopted the EIC, with no impact on its consolidated financial statements.

In June 2009, the CICA Handbook Section 3862, Financial Instruments – Disclosures, was amended to require disclosures about the inputs to fair value measurements, including their classification within a hierarchy that prioritizes the inputs to fair value measurement. The three levels of the fair value hierarchy are:

Level 1 – Unadjusted quoted prices in active markets for identical assets or liabilities;
Level 2 – Inputs other than quoted prices that are observable for the asset or liability either directly or indirectly; and
Level 3 – Inputs that are not based on observable market data

The Company immediately adopted this amended standard and the required disclosures are included in Note 15 to the consolidated financial statements.

Future Canadian Accounting Pronouncements

Business Combinations (Section 1582)

In January 2009, the CICA issued Handbook Section 1582, "Business Combinations", which requires that all assets and liabilities of an acquired business be recorded at fair value at acquisition. Obligations for contingent considerations and contingencies will also be recorded at fair value at the acquisition date. The standard also states that acquisition-related costs will be expensed as incurred and that restructuring charges will be expensed in the period after the acquisition date. The Section applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period on or after January 1, 2011.

The Company has early adopted this Standard effective January 1, 2010 for the fiscal year ending December 31, 2010. There was no material impact on the consolidated financial statements as a result of this adoption.

Consolidations (Section 1601) and Non-Controlling Interest (Section 1602)

In January 2009, the CICA issued Handbook Section 1601, "Consolidations" ("CICA 1601"), and Section 1602, "Non-Controlling Interests" (CICA 1602"). CICA 1601 establishes standards for preparing consolidated financial statements and CICA 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. These standards apply to interim and annual consolidated financial statements relating to fiscal years beginning on or after January 1, 2011.

The Company has early adopted these Standards effective January 1, 2010 for the fiscal year ending December 31, 2010. There was no material impact on the consolidated financial statements as a result of this adoption

International Financial Reporting Standards ("IFRS")

In 2006, the Canadian Accounting Standards Board ("AcSB") published a new strategic plan that will significantly affect financial reporting requirements for Canadian companies. The AcSB strategic plan outlines the convergence of Canadian GAAP with IRFS over an expected five year transitional period. In February 2008 the AcSB announced that 2011 is the changeover date for the publicly-listed companies to use IFRS, replacing Canada's own GAAP. The date is for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. The transition date of January 1, 2011 will require the restatement for comparative purposes of amounts reported by the Company for the year ended December 31, 2010. While the Company has begun assessing the adoption of IFRS for 2011, the financial reporting impact of the transition to IFRS cannot be reasonably estimated at this time.

Business Risks:

Exploration and development of oil and gas reserves is speculative and involves a significant degree of risk. There is no guarantee that exploration and development of properties will lead to a discovery. The success of our business depends on our ability to successfully drill and complete producing oil and natural gas wells. Drilling may yield uneconomic efforts, through either dry wells or those which are not sufficiently productive to justify commercial development. In addition, the price we receive for our product dictates the amount of revenues we will receive. A material decline in the price of oil and gas may have an affect on Mountainview's financial condition. The current price of oil and natural gas continues to fluctuate and there is an expectation that the Company's cash reserves will be directly affected.

The Company needs to continue the development of our oil and natural gas properties in order to grow and achieve financial profitability.

Mountainview is a small Company and is dependent on the efforts of its existing Management. Should the Company's Management become unavailable for any reason, a disruption in operations could result, thus having a material effect on the Company's financial condition

Subsequent Events

Subsequent to the year end the Company signed a letter of intent to enter into an agreement to acquire a 100% working interest of the third parties 30% interest in all wells and oil and gas leases in the Snoose Coulee Field located in Liberty County, Montana for $55,000.

Approval

The Audit Committee of Mountainview Energy Ltd has approved the disclosure contained in this MD&A. A copy of this MD&A will be provided to anyone who requests it.

"Patrick M. Montalban"

Patrick M. Montalban
President & Chief Executive Officer **Date: April 30, 2010**