



STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

FORM 51-101F1

Effective December 31, 2012

April 30, 2013

CERTAIN DEFINITIONS

This statement of reserves data and other oil and gas information (the "**Statement**") of Mountainview Energy Inc. ("**Mountainview**" or the "**Company**") uses the following definitions from the report ("**Sproule Report**") prepared by Sproule Associates Ltd. ("**Sproule**"), as described herein. The definitions have been prepared by the Standing Committee on Reserves Definitions of the Petroleum Society of the CIM, incorporated in the Society of Petroleum Evaluation Engineers' Canadian Oil and Gas Evaluation Handbook ("**COGE Handbook**") and specified by National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**").

"**Reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology;
- specified economic conditions, which are generally accepted as being reasonable; and
- a remaining reserve life of 50 years.

Reserves are classified according to the degree of certainty associated with the estimates.

"**Proved Reserves**" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

"**Probable Reserves**" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

"**Possible Reserves**" are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. Possible reserves have not been considered in this report.

Other criteria that must also be met for the categorization of reserves are provided in Section 5.5 of the COGE Handbook.

Each of the reserves categories (proved, probable, and possible) may be divided into developed or undeveloped categories.

"**Developed Reserves**" are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and nonproducing.

"**Developed Producing Reserves**" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"**Developed Non-Producing Reserves**" are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

"**Undeveloped Reserves**" are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

All dollar amounts herein are in Canadian dollars, unless otherwise stated.

PROPERTY DESCRIPTIONS

South Alberta Basin, USA

Red Creek

Mountainview own a 100% working interest in approximately 2,500 net acres located within the Red Creek Property, located in Glacier County, Montana. Mountainview intends to continue its workover and development program in the Red Creek area, with a few existing wells to be brought back on stream. The Company will plan to drill 1 to 2 wells per year to continue developing the field.

Lake Frances

The Lake Frances Project is comprised 37,829.90 gross (32,191 net) acres of petroleum and natural gas lands, of which 4,000 gross (3,750 net) acres have been developed with 25 gross (18.75 net) wells drilled on 160 acre spacing. The total acreage, including an undeveloped area totaling 33,829.90 gross (28,441 net) acres is located in Pondera County, Montana. While the acreage is not all contiguous, it is anticipated that the development will continue on a 160 acre spacing basis. Development on this property will not commence until there is an increase in the price of natural gas.

Williams

The Williams Project is comprised 18,273.13 gross (14,922 net) acres of petroleum and natural gas lands, of which 11,520 gross (11,520 net) acres have been developed with 18 gross (18 net) wells drilled on 640 acre spacing. The total acreage, including an undeveloped area encompassing 6,753 a gross (3,402 net) acres is located in Pondera County, Montana. The acreage is relatively contiguous, thus development will continue, however development is expected to be effected on a 320 acre spacing basis rather than the existing 640 acres. Development on this property will not commence until there is an increase in the price of natural gas.

Loneman Coulee

Effective August 31, 2010, the Company accepted assignment of all of Altamont Oil & Gas, Inc.'s right, title and interest in the Loneman Coulee located in Pondera County and consisting of acres 1,718.42. Located within this acreage are four wells of which the Company has now become the Operator. On the property there exists currently one producing oil well and one shut-in oil well. The remaining wells were converted to a water disposal system for handling the disposal of water for other operators developing the South Alberta Bakken.

Pondera

Mountainview 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, Montana 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, two wells were drilled and completed on this property in 2009 and both wells continue to produce to date. There are no current plans to further develop this property.

Snoose Coulee

Effective April 1, 2010 the Company acquired 100% of a third party's 30% right, title and interest in the Snoose Coulee Field located in Liberty County, Montana for \$55,000. Included with this acquisition is a working and royalty interest in 14 natural gas wells

Williston Basin, USA

12 Gage

Mountainview own a 100% working interest in approximately 13,130 net acres located in the 12 Gage Prospect located in Divide County, North Dakota. Mountainview commenced a three-well drilling program in November 2012 and has drilled and completed three wells to date. Following are the results of this drilling program:

Wigness 5-8-1H:

Upon completion of the successful fracing operations on the Wigness 5-8-1H well (the "Wigness Well"), the Company's first horizontal Three Forks well in its three-well winter drilling program, Mountainview conducted a 6-day production/flow test. During the 6 day period the well flowed on a 32/64" choke and the well averaged 355 barrels of oil per day, 228 mcf of gas per day and 998 barrels of water per day. The peak production rate on the 6th day was 383 barrels of oil per day, 352 mcf of gas per day and 1,212 barrels of water per day.

The Company installed an artificial lift system and placed the Wigness well on production on February 16, 2013 and it has produced intermittingly due to a gas lock issue. During the time that the Wigness well has been on production, it has averaged 276 barrels of oil per day, and 236 mcf/d of natural gas for a total of 313 boe/d (294 boe/d net).

Leininger 3-10-1H

The Leininger 3-10-1H well (the "**Leininger Well**"), the second horizontal Three Forks well in Mountainview's three-well winter drilling program, flowed for three days during the completion program at an average rate of 380 bopd, 230 mcf/d, and 1,088 bwpd. The Company proceeded with the completion program by moving a service rig onto the well and milling out the 25 bridge plugs from the plug and perf fracture stimulation. After cleaning the well out properly the Company installed an artificial lift system and placed the well on production on March 14, 2013. Since the well has been on production it has averaged 348 bopd, 636.5 mcf/d, and 772 bwpd. The peak production rate on the first day of production was 557 boe/d, comprised of 427 bopd, 838 mcf/d, and 1,004 bwpd.

During the time that the Leininger well has been on production, it has averaged 256 barrels of oil per day and 399 mcf/d of natural gas for a total of 324 boe/d (283 boe/d net).

Olson 35-26-1H

The Olson 35-26-1H (the "**Olson Well**") is the final well in the three-well winter drilling program on Mountainview's 12 Gage Project and is located approximately 2-3 miles north-east of the Leininger Well. The Olson well was drilled in 16 days, which is the same amount of time it took to drill the Leininger Well.

Mountainview completed the clean-out operations following the 26 stage plug and perf fracture stimulation on the Olson 35-26-1H well and installed an artificial lift system on the well and placed the well on production April 11, 2013. The peak production day for the initial four day test on this well was 391 barrels of oil per day and 1,089 mcf/d of natural gas for a total of 574 boe/d (357 boe/d net). During that four day test the well averaged 267 barrels of oil per day and 649 mcf/d of natural gas for a total of 372 boe/d (232 boe/d net).

The Company is waiting to report the results of a 30-day average production test on all three wells, as we are still producing a major portion of the water (or load) from the frac stimulation.

Medicine Lake

The Medicine Lake is comprised of certain non-operated oil and natural gas assets and undeveloped acreage located in the Medicine Lake prospect in Divide and Williams County, North Dakota and Roosevelt and Sheridan County, Montana, consisting of approximately 44,181 gross (8,836 net) acres of undeveloped land.

Mountainview current holds a non-operated working interest in 13 wells under the Medicine Lake Property with those interests varying from as low as 1% to as high as 12.5%.

**STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION OF
MOUNTAINVIEW ENERGY LTD.**

Effective December 31, 2012

FORM 51-101F1

Part 1 Date of Statement

Item 1.1 Relevant Dates

This Statement is dated April 30, 2013. The effective date of the Statement is December 31, 2012 unless otherwise indicated and the preparation date of the Statement is April 30, 2013.

Part 2 Disclosure of Reserves Data

In accordance with NI 51-101, the reserves data of the Company as set forth below (the "**Reserves Data**") is based upon an independent evaluation by Sproule with an effective date of December 31, 2012 contained in the Sproule Report.

All evaluations of future revenue are after the deduction of future income tax expenses, unless otherwise noted in the tables, royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables do not necessarily represent the fair market value of the Company's reserves. There is not assurance that the forecast price and cost assumptions contained in the Sproule Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the Sproule Report. The recovery and reserves estimates on the Company's properties described herein are estimates only. The actual reserves on the Company's properties may be greater or less than those calculated.

Item 2.1 Reserves Data (Forecast Prices and Costs)

Table 2.1.1 "Summary of Reserves as of December 31, 2012" discloses, in the aggregate, the Company's gross and net proved reserves, proved plus probable reserves and proved plus probable plus possible reserves, estimated using forecast prices and costs, by product type. "Forecast prices and costs" are future prices and costs "generally accepted as being a reasonable outlook of the future".

Table 2.1.2 "Summary of Net Present Values of Future Net Revenue as of December 31, 2012" discloses, in the aggregate, the net present value of the Company's future net revenue attributable to the reserves categories in the previous table, estimated using forecast prices and costs, before and after deducting future income tax expenses, and calculated without discount and using discount rates of 5%, 10%, 15% and 20%.

Table 2.1.3 "Total Future Net Revenue (Undiscounted) as of December 31, 2012" discloses, in the aggregate, certain elements of the Company's future net revenue attributable to its proved reserves and its proved plus probable reserves, estimated using forecast prices and costs, and calculated without discount.

Table 2.1.4 "Future Net Revenue by Production Group as of December 31, 2012" discloses, by production group, the net present value of the Company's future net revenue attributable to its proved reserves and its proved plus probable reserves, before deducting future income tax expenses, estimated using forecast prices and costs, and calculated using a 10% discount rate.

Table 2.1.1
SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2012
FORECAST PRICES AND COSTS

	Reserves					
	Light and Medium Oil		Natural Gas		Total Barrels Oil Equivalent	
	Gross ⁽¹⁾ (Mbbbl)	Net ⁽²⁾ (Mbbbl)	Gross ⁽¹⁾ (MMcf)	Net ⁽²⁾ (MMcf)	Gross ⁽¹⁾ (Mbbbl)	Net ⁽²⁾ (Mbbbl)
Proved Developed Producing	382.5	339.9	473	388	461.3	404.6
Proved Developed Non-Producing	-	-	-	-	-	-
Proved Undeveloped	-	-	-	-	-	-
Total Proved	382.5	339.9	473	388	461.3	404.6
Total Probable	289.9	206.8	115	95	309.1	222.5
Total Proved Plus Probable	672.4	546.7	588	482	770.4	627.1

Table 2.1.2
SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2012
FORECAST PRICES AND COSTS

	Before Income Taxes Discounted At					After Income Taxes Discounted At					Before Tax Net Value 10%/yr (\$/boe)
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%	
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	
Proved Developed Producing	12,999	10,363	8,593	7,343	6,424	11,052	8,839	7,352	6,302	5,530	21.24
Proved Developed Non-Producing											
Proved Undeveloped											
Total Proved	12,999	10,363	8,593	7,343	6,424	11,052	8,839	7,352	6,302	5,530	21.24
Total Probable	8,279	5,286	3,665	2,684	2,038	4,976	2,889	1,792	1,143	720	16.47
Total Proved Plus Probable	21,278	15,650	12,258	10,028	8,462	16,028	11,728	9,144	7,445	6,250	19.55

Table 2.1.3
TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2012
FORECAST PRICES AND COSTS

	Revenue (M\$)	Royalties (M\$)	Operating Costs (M\$)	Development Costs (M\$)	Well Abandonment and Other Costs (M\$)	Future Net Revenue Before Income Taxes (M\$)	Income Taxes (M\$)	Future Net Revenue After Income Taxes (M\$)
Total Proved	35,480	6,220	15,730	-	530	12,999	1,947	11,052
Total Proved Plus Probable	63,890	16,302	23,424	2,301	586	21,278	5,250	16,028

Table 2.1.4
FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2012
FORECAST PRICES AND COSTS

	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M\$)	Unit Value Before Income Taxes Discounted at 10%/Year \$/BOE
Total Proved ^c	Light and medium crude oil (including solution gas and associated by-products)	8,263	24.31
	Natural Gas (including associated gas by-products)	330	5.11
	Total	8,593	21.24
Total Proved Plus Probable	Light and medium crude oil (including solution gas and associated by-products)	11,842	21.66
	Natural Gas (including associated gas by-products)	417	5.18
	Total	12,258	19.55

PART 3 PRICING ASSUMPTIONS

Forecast Prices Used in Estimates

The following tables set forth the forecast reference prices, effective December 31, 2012, used by Sproule in preparing Mountainview's Reserves Data.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as at December 31, 2011
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma (\$US/bbl)	Edmonton Par Price (\$Cdn/bbl)	Henry Hub Price (\$US/MMBtu)	Natural Gas AECO Gas Prices (\$Cdn/MMBtu)	Inflation Rate %/year	Exchange Rate \$US/\$Cdn
Historical						
2008	99.59	102.85	9.04	8.15	1.1	0.943
2009	61.63	66.20	4.01	4.19	2.0	0.880
2010	79.43	77.80	4.39	4.16	1.2	0.971
2011	95.00	95.16	4.04	3.72	1.6	1.012
2012	94.19	86.53	2.79	2.43	1.3	1.001
Forecast						
2013	89.63	84.55	3.65	3.31	1.5	1.001
2014	89.93	89.84	4.06	3.72	1.5	1.001
2015	88.29	88.21	4.24	3.91	1.5	1.001
2016	95.52	95.43	5.04	4.70	1.5	1.001
2017	96.96	96.87	5.66	5.32	1.5	1.001
2018	98.41	98.32	5.74	5.40	1.5	1.001
2019	99.89	99.79	5.83	5.49	1.5	1.001
2020	101.38	101.29	5.91	5.58	1.5	1.001
2021	102.91	102.81	6.00	5.67	1.5	1.001
2022	104.45	104.35	6.09	5.76	1.5	1.001
2023	106.02	105.92	6.18	5.85	1.5	1.001
Thereafter			Escalation Rate of 1.5%			

PART 4 RECONCILIATION OF CHANGES IN RESERVES

Item 4.1 Reserves Reconciliation

The following table provides a reconciliation of Mountainview's gross reserves based on forecast prices and costs.

Table 4.1
RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE
as of December 31, 2012
FORECAST PRICES AND COSTS

FACTORS	Light and Medium Oil			Associated, Non-Associated and Solution Gas			BOEs		
	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)
December, 31, 2011	464.0	10.0	474.0	74	0	74	476.3	10.0	486.3
Extension	0.0	204.2	204.2	0	0	0	0.0	204.2	204.2
Infill Drilling	0.0	0.0	0.0	0	0	0	0.0	0.0	0.0
Improved Recovery	0.0	0.0	0.0	0	0	0	0.0	0.0	0.0
Technical Revisions	(145.1)	66.3	(78.8)	(10)	7	(3)	(146.8)	67.5	(79.4)
Discoveries	6.6	3.2	9.8	0	0	0	6.6	3.2	9.8
Acquisitions	19.5	6.2	25.7	367	78	445	80.7	19.2	99.9
Dispositions	0.0	0.0	0.0	0	0	0	0.0	0.0	0.0
Economic Factors	0.0	0.0	0.0	0	0	0	0.0	0.0	0.0
Production	37.5	0.0	37.5	42	0	42	44.5	0.0	44.5
December 31, 2012	382.5	289.9	672.4	473	85	558	461.3	304.1	765.4

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 Undeveloped Reserves

Undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Proved and probable undeveloped reserves have been assigned in accordance with engineering and geological practices as defined under NI 51 101.

As set forth in the tables below, the Company does not have any proved undeveloped reserves. The Company plans to develop all of the probable undeveloped reserves over the next five years. The development program is contingent on obtaining sufficient capital.

There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to commodity pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion formation is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals).

The following tables sets forth the gross volumes of proved undeveloped reserves and probable undeveloped reserves that were attributed for each of the Company's product types for the most recent three financial years and, in the aggregate, before that time.

Table 5.1.1
SUMMARY OF PROVED UNDEVELOPED RESERVES
as of December 31, 2012
FORECAST PRICES AND COSTS

	Light and Medium Oil (mdbl)		Natural Gas (mmcf)	
	First Attributed	Booked Gross	First Attributed	Booked Gross
Prior thereto	-	-	-	-
December 31, 2010	-	-	-	-
December 31, 2011	-	-	-	-
December 31, 2012	-	-	-	-

Table 5.1.2
SUMMARY OF PROBABLE UNDEVELOPED RESERVES
as of December 31, 2012
FORECAST PRICES AND COSTS

	Light and Medium Oil (mdbl)		Natural Gas (mmcf)	
	First Attributed	Booked Gross	First Attributed	Booked Gross
Prior thereto	-	-	-	-
December 31, 2010	-	-	-	-
December 31, 2011	-	-	-	-
December 31, 2012	204.2	204.2	-	-

Item 5.2 Significant Factors or Uncertainties Affecting Reserves Data

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and natural gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

The estimation of reserves requires significant judgment and decisions based on available geological, geophysical, engineering and economic data. As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in yearend prices, reservoir performance and geologic conditions or production.

The Company does not anticipate any significant economic factors or significant uncertainties will affect any particular components of this statement of reserves data and other oil and gas information. However, reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond the Company's control.

Item 5.3 Future Development Costs

The following table sets out the development costs deducted in the estimation of future net revenue attributable to proved reserves (using forecast prices and costs) and proved plus probable reserves (using forecast prices and costs) based upon the Sproule Report.

Table 5.3.1
FUTURE DEVELOPMENT COSTS
Undiscounted and Discounted at 10%
as of December 31, 2012
FORECAST PRICES AND COSTS

Year	Total Proved Estimated Using Forecast Prices and Costs (M\$)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs (M\$)
2013	-	2,301
2014	-	-
2015	-	-
Total for all years undiscounted	-	2,301
Total for all years discounted at 10%/year	-	2,289

Mountainview expects to use a combination of internally generated cash from operations, working capital and the issuance of new equity or debt where and when it believes appropriate to fund future development costs set out in the Sproule Report. There can be no guarantee that funds will be available or that the board of directors of the Company will allocate funding to develop all of the reserves attributable in the Sproule Report. Failure to develop those reserves could have a negative impact on the Company's future cash flow.

The Company does not anticipate that interest or other funding costs would make further development of any of the Company's properties uneconomic.

Part 6 Other Oil and Gas Information

Item 6.1 Oil and Gas Properties and Wells

The following table sets forth the number of wells in which the Company held a working interest as at December 31, 2012:

	Oil		Natural Gas	
	Gross ⁽¹⁾	Net ⁽¹⁾	Gross ⁽¹⁾	Net ⁽¹⁾
Red Creek				
Producing	35	35	-	-
Non-producing	3	3	-	-
Williams				
Producing	-	-	17	17
Non-Producing	-	-	1	1
Lake Frances				
Producing	-	-	25	18.75
Non-Producing	-	-	-	-
Loneman Coulee				
Producing	1	0.5	-	-
Non-Producing	1	0.5	-	-
Pondera/Donovan				
Producing	2	1.5	-	-
Non-Producing	-	-	-	-
Snoose Coulee				
Producing	-	-	13	4.29
Non-Producing	-	-	1	0.33
Medicine Lake				
Producing	11	0.5	-	-
Non-Producing	-	-	-	-
12-Gage				
Producing	1	0.67	-	-
Non-Producing	-	-	-	-
TOTALS:	54	41.67	57	41.37

Item 6.2 Properties with No Attributed Reserves

	Location	Gross Acres	Net Acres
Medicine Lake	Roosevelt & Sheridan County, MT & Williams & Divide County, ND	44,181	8,836
12-Gage	Divide County, ND	20,245	13,130

The Company holds multiple well bonds in both Montana and North Dakota. In addition, the Company is subject to drilling timelines based on the lease requirements. Under the 12-Gage property, the Company owns 100% of mineral interests in 12,579 Net Acres from surface to the top of the Bird Bear Formation. In addition, the Company is restricted to a 20% interest in 5,647 acres below the top of the Bird Bear.

Item 6.2.1 Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

The significant factors or uncertainties relevant to the properties with no attributed reserves are: commodity prices, regulations over hydraulic fracturing and insufficient funding to undertake development.

Item 6.3 Forward Contracts

As at December 31, 2012, Mountainview had no outstanding forward commodity or foreign exchange contracts.

Item 6.4 Additional Information Concerning Abandonment and Reclamation Costs

Mountainview uses the industry average for abandonment costs, which is \$5,000 per well in the Red Creek area, \$1,500 per well in the Lake Frances field and \$75,000 per well in the Medicine Lake field.

Item 6.5 Tax Horizon

The Company is subject to tax in the State of Montana and North Dakota along with US Federal Income Tax.

Item 6.6 Costs Incurred

The following table summarizes the capital expenditures made by the Company on oil and natural gas properties for the year ended December 31, 2012.

Property Acquisition Costs (M\$)		Exploration Costs (M\$)	Development Costs (M\$)
Proved Properties	Unproved Properties		
\$5,579,708	\$22,410,632	-	\$7,199,268

Item 6.7 Exploration and Development Activities

The following table sets forth the number of exploratory and development wells which the Company completed during its 2012 financial year:

	Exploratory Wells		Development Wells	
	Gross ⁽¹⁾	Net ⁽¹⁾	Gross ⁽¹⁾	Net ⁽¹⁾
Oil Wells	11	0.5	-	-
Gas Wells	-	-	-	-
Service Wells	-	-	-	-
Stratigraphic Test Wells	-	-	-	-
Dry Holes	-	-	-	-
Total Completed Wells	-	-	-	-

Notes:

- (1) "Gross" means the total number of wells in which the Company has an interest.
- (2) "Net" means the number of wells obtained by aggregating the Company's interest in each of its gross wells.

See also *Property Descriptions* for a description of Mountainview's current and proposed exploration and development activities.

Item 6.8 Production Estimates

The following table sets forth for each product type the volume of production estimated for the year ended December 31, 2013, which is reflected in the estimates of gross proved reserves and gross probable reserves disclosed under Item 2.1 – *Reserves Data (Forecast Prices and Costs)*.

	Gross Proved		Gross Probable	
	Light and Medium Oil (Mbbbl)	Natural Gas (MMcf)	Light and Medium Oil (Mbbbl)	Natural Gas (MMcf)
Red Creek(MT)	31.9	0	0	0
Lake Frances (MT)	0	21.9	0	0.4
Loneman Coulee (MT)	0.4	0	0.1	0
Medicine Lake (MT)	3.3	0	0.1	0
Pondera (MT)	0.8	0	0	0
Snoose Coulee (MT)	0	4.4	0	0
Williams (MT)	0	38.5	0	0.2
12 Gage (ND)		0	36.3	0
Medicine Lake (ND)	8.1	0	0.5	0
Total	44.5	64.8	37.0	0.6