Management Discussion and Analysis

Dated as of April 30, 2015

INTRODUCTION

The following Management Discussion and Analysis ("MD&A") is management's assessment of Mountainview Energy Ltd.'s ("Mountainview" or the "Company") financial and operating results and should be read in conjunction with the audited financial statements of the Company for the year ended December 31, 2014 and the audited financial statements and MD&A for the year ended December 31, 2013. This MD&A is presented in U.S. dollars (except where otherwise noted). Additional information relating to the Company can be found on www.sedar.com.

Mountainview Energy Ltd. ("Mountainview" or "the Company") was incorporated under the laws of the Province of British Columbia, Canada and was continued into the Province of Alberta in May, 2012. Its principal business is the exploration, acquisition, development and production of petroleum and natural gas reserves in the State of Montana, and the State of North Dakota, USA. The Company's shares are traded on the TSX Venture Exchange ("TSX-V") under the symbol "MVW" and the Company's head office is located at 33 First Avenue SW, Cut Bank Montana, 59427-0222, U.S.A. The Company had the following direct and indirect wholly-owned subsidiaries at December 31, 2014.

- Mountainview Energy (USA) Ltd.
- Mountain View Energy, Inc.
- Mountainview Energy, LLC
- Mountain Divide, LLC
- Numbers, Inc.
- Mountainview Gathering Inc.
- Immgen Inc.
- DBD Investments Inc.
- MC2 Inc.

Non-GAAP Measures – Certain measures in this document do not have a standardized meaning as prescribed by IFRS, such as operating netback[(1)], funds flow from operations[(2)], funds flow per share, and net debt[(3)] and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. The term funds flow from operations or funds flow should not be considered an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with IFRS as an indicator of the Company's performance. Management's use of these measures has been disclosed further in this document as these measures are discussed and presented.

(1) Operating netback is a non-GAAP measure calculated as the average per boe of the Company's oil and gas sales plus realized gains on derivatives, less royalties, operating and transportation expenses.

(2) Funds flow from operations should not be considered an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with International Financial Reporting Standards as an indicator of Mountainview's performance. Funds flow from operations represents cash flow from operating activities prior to changes in non-cash working capital, transaction costs and decommissioning provision expenditures incurred. Mountainview also presents funds flow from operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of earnings per share.

(3) Net debt is a non-GAAP measure representing the total of bank indebtedness, accounts payables and accrued liabilities, less accounts receivables, deposits and prepaid expenses.

Basis of Presentation – The reporting and measurement currency is the U.S. dollar.

boe Presentation – All calculations converting natural gas and natural gas liquids to barrels of oil equivalent ("boe") have been made using a conversion ratio of six thousand cubic feet (six "Mcf") of natural gas to one barrel of oil, and 55 gallons of natural gas liquids to one barrel of oil, unless otherwise stated. The use of boe may be misleading, particularly if used in isolation, as the conversion ratio of six Mcf of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

GOING CONCERN

As at December 31, 2014, the following conditions existed:

1. The Company had a working capital deficit of $71,403,601.
2. The Company incurred a loss from operations totaling $71,847,789 for the year ended December 31, 2014.
3. The Company does not anticipate generating sufficient funds from operations to fund its working capital deficit and had negative cash flows from operations of $1,960,684 for the year ended December 31, 2014.
4. Commodity prices had decreased by 57% over the second half of 2014.

The Company has experienced losses in the years ended December 31, 2014 and December 31, 2013. At December 31, 2014 and December 31, 2013, the Company had a deficit of $71,847,790 and $17,500,630 respectively, and a working capital deficit of $71,403,601 and $5,236,932 respectively. Continuing operations, as intended, are dependent on management's ability to raise required funding through future equity issuances, credit facilities, asset sales or a combination thereof, which is not assured, especially in current volatile and uncertain financial and commodity price environment. The sharp decline in commodity prices during the latter half of 2014 materially reduced the revenues that were generated from the sale of oil and gas production volumes during that period which, in turn, negatively affected the Company's working capital balance and the ability of the Company to secure additional financing. There is potential for future commodity prices to remain at current price levels for an extended period of time and should the current commodity price environment continue for a prolonged period of time, the Company will need to negotiate with its creditors to improve payment terms and/or pursue some form of asset sale, debt restricting, equity financing or other capital raising effort in order to fund its operations and to service its existing debt during the next twelve months. In addition, liens have been filed on the Company's assets in the months subsequent to December 31, 2014. While these liens do not presently impact cash flow, the vendors who have filed the liens may, in fact, restrict cash flow from the wells under lien, further reducing the cash flow available to the Company. Any sale of assets with outstanding liens would require that the lien be cleared before title can be transferred. This condition also limits the proceeds of any potential asset sale. The Company is also in breach of debt covenants under the agreements governing the line of credit and credit facility (See Note 12 in the Audited Financial Statements). The line of credit and credit facility mature and are due and payable in 2015 (See Note 9 in the Audited Financial Statements). Management of the Company is actively pursuing strategies to improve its working capital position and/or to reduce its future debt service costs, through the aforementioned means. The Company believes that these actions will mitigate the adverse conditions that the Company is facing; however, there is no certainty that these and other strategies will be successful or permit the Company to continue as a going concern.

These material uncertainties cast significant doubt on the Company's ability to continue as a going concern. If the Company is unable to restructure its debt in an acceptable manner, obtain additional adequate debt or equity financing or achieve adequate proceeds from the sale of assets, the Company will pursue all other legal avenues available to it with a view to improving the Company's financial situation in the best interests

of the Company. These audited consolidated financial statements do not include any adjustments to the recoverability and classification of recorded asset amounts and classification of liabilities and related expenses that might be necessary, should the Company be unable to continue as a going concern. Should the going concern assumption not be appropriate and the Company is not able to realize its assets and settle its liabilities, these statements would require adjustments to the amounts and classifications of assets and liabilities and these adjustments could be material.

FORWARD-LOOKING STATEMENTS OR INFORMATION

Certain statements contained in this MD&A constitute forward-looking statements or information within the meaning of securities laws. Forward-looking statements or information may relate to our future outlook and anticipated events or results and may include statements regarding the future financial position, business strategy, budgets, projected costs, capital expenditures, financial results, taxes and plans and objectives of or involving Mountainview. Particularly, statements regarding future operating results and economic performance are forward-looking statements. In some cases, forward-looking information can be identified by terms such as “may”, “will”, “should”, “expect”, “plan”, “anticipate”, “believe”, “intend”, “estimate”, “predict”, “potential”, “continue” or other similar expressions concerning matters that are not historical facts.

These statements are based on certain factors and assumptions regarding, among other things, expected growth, results of operations, performance, business prospects and opportunities, the impact of increasing competition; the general stability of the economic and political environment in which Mountainview operates; the timely receipt of any required regulatory approvals; the ability of Mountainview to obtain qualified staff, equipment and services in a timely and cost efficient manner; the ability of Mountainview to issue debt or equity, to service debt and fund operations, the ability of Mountainview or the operator of the projects which Mountainview has an interest in to operate the field in a safe, efficient and effective manner; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development or exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Mountainview to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Mountainview operates; and the ability of Mountainview to successfully market its oil and natural gas products. Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions which have been used. While we consider these assumptions to be reasonable based on information currently available to us, they may prove to be incorrect.

Forward looking-information is also subject to certain factors, including risks and uncertainties that could cause actual results to differ materially from what we currently expect. These factors include the ability of management to execute its business plan; general economic and business conditions; the risk of instability affecting the jurisdictions in which Mountainview operates; the risks of the oil and natural gas industry, such as operational risks in exploring for, developing and producing crude oil and natural gas and market demand; the possibility that government policies or laws may change or governmental approvals may be delayed or withheld; risks and uncertainties involving geology of oil and natural gas deposits; the uncertainty of reserves estimates and reserves life; the ability of Mountainview to add production and reserves through acquisition, development and exploration activities; Mountainview's ability to enter into or renew leases; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of estimates and projections relating to production (including decline rates), costs and expenses; fluctuations in oil and natural gas prices, foreign currency exchange rates and interest rates; risks inherent in Mountainview's marketing operations, including credit risk; uncertainty in amounts and timing of royalty payments; health, safety and environmental risks; risks associated with potential future law suits and regulatory actions against Mountainview; uncertainties as to the availability and cost of financing; and financial risks affecting the value of Mountainview's investments. Readers are cautioned that the foregoing list is not exhaustive of all possible risks and uncertainties.

All statements, other than statements of historical fact, which address activities, events, or developments that Mountainview expects or anticipates will or may occur in the future, are forward-looking statements within the meaning of applicable securities laws. These statements are subject to certain risks and uncertainties, and may be based on estimates or assumptions that could cause actual results to differ materially from those anticipated or implied.

Any financial outlook or future oriented financial information in this presentation, as defined by applicable securities legislation, has been approved by management of Mountainview. Such financial outlook or future oriented financial information is provided for the purpose of providing information about management's current expectations and plans relating to Mountainview Energy Ltd and its subsidiaries, drilling plans, production forecasts, operating costs or any future market activity. Readers are cautioned that reliance on such information may not be appropriate for other purposes.

Please see “Assessment of Business Risks” in this MD&A.

Additional information relating to Mountainview, including Mountainview’s annual information form and financial statements can be found on SEDAR at www. sedar.com or the Company’s website at: www.mountainviewenergy.com,

INITIAL PRODUCTION

Any references in this MD&A to test rates, flow rates, initial and/or final raw test or production rates, early production, test volumes and/or "flush" production rates are useful in confirming the presence of hydrocarbons, however, such rates are not necessarily indicative of long-term performance or of ultimate recovery. Such rates may also include recovered "load" fluids used in well completion stimulation. Readers are cautioned not to place reliance on such rates in calculating the aggregate production for Mountainview. In addition, certain of Mountainview's assets may be subject to high initial decline rates. While Mountainview discloses the initial results from new wells, the information disclosed herein should be considered preliminary and is not indicative of long-term performance. Ongoing technical work and operational enhancements are expected to continue to improve the Company's understanding of the ultimate potential of its assets.

PETROLEUM AND NATURAL GAS SALES

Mountainview realized the following sales volume, and commodity prices for the referenced periods:

	Three months ended December 31		Year ended December 31	
	2014	2013	2014	2013
Sales ($000's)				
Light oil	5,000	7,363	23,671	20,263
Natural gas	50	55	283	264
Natural gas liquids	58	-	154	-
Total petroleum and natural gas sales	5,108	7,418	24,108	20,527
Average Daily Sales Volume				
Light oil (bbl/day)	880	1,039	802	644
Natural gas (Mcf/day)	182	864	219	632
Natural gas liquids (boe/day)	17	-	14	-
Total (boe/d)	927	1,183	853	749
% oil and NGL production	97%	88%	96%	86%
Average Mountainview Realized Commodity Prices				
Light oil ($ per bbl)	63.15	77.02	80.81	86.20
Natural gas ($ per Mcf)	3.07	2.94	3.53	2.98
Natural gas liquids ($ per bbl)	36.01	-	41.89	-
Barrels of oil equivalent ($ per boe, 6:1)	61.16	68.16	77.78	75.08
Benchmark Pricing				
WTI crude oil (US$ per bbl)	73.15	97.44	93.00	97.96
NYMEX natural gas (US$ per MCF)	3.85	3.85	4.28	3.73
Exchange rate (US$/Cdn$)	0.88	0.94	0.91	0.97

Sales for the three months and year ended December 31, 2014 were $5.1 million and $24.1 million, respectively, compared to $7.4 million and $20.5 million for the three months and year ended December 31, 2013, respectively. This represents a decrease of $2.3 million, or 31%, over the prior period quarter and an increase of $3.6 million, or 18%, over the year ended December 31, 2013. Excluding the impact of derivative instruments, the average realized commodity price decreased from $77.78 per boe in the fourth quarter of 2013 to $61.16 per boe during the fourth quarter of 2014. This 21% decrease in realized price is due to a lower WTI benchmark price, upon which the Company's sales contract is based. Compared to the prior year quarter, the WTI crude oil benchmark decreased $24.29 per bbl, or 25%. This decrease was partially offset by narrowing discounts between benchmark WTI and sales contract pricing in North Dakota, where the majority of the Company's oil is produced. This realized price discount is the result of transportation costs and overall production increases in North Dakota, leading to take away capacity constraints. Average daily production volumes decreased by 256 boe/d, or 22%, when compared to the prior period quarter and, when compounded by the decrease in the average realized commodity price, the result is a negative $2.3 million impact on the total sales revenue on a quarter over prior period quarter basis. On a year over year basis, the average daily production rates are 1.4 times higher in 2014, reflecting the successful development of the Company's 12 Gage asset base in late 2013 and early 2014. In addition, higher crude pricing for the first three quarters of 2014 have resulted in a higher year over year average realized price. The higher average daily production, combined with slightly higher average realized commodity pricing resulted in an increase in sales for the year ended December 31, 2014.

The Company has not recently targeted gas-based drilling, however the associated gas produced in Divide County has been tied in with first natural gas liquids sales from Divide County in March, 2014. This added revenue stream will ensure the Company is getting full value for its reserves produced. Natural gas sales currently account for 3% of production volumes, and only 1% of sales revenue.

ROYALTIES

	Three months ended December 31		Year ended December 31	
($000's except per boe amounts)	2014	2013	2014	2013
Light oil	866	1,461	4,342	3,301
Natural gas	7	7	41	29
Natural gas liquids	11	-	30	-
Total royalties	884	1,468	4,413	3,330
Total royalties per boe	10.58	13.49	14.24	12.18
% of P&NG Sales	17.3%	20.0%	18.3%	16.0%

Royalties for the three months and year ended December 31, 2014 were $0.9 million and $4.5 million, respectively, compared to $1.5 million and $3.3 million, respectively, for the three months and year ended December 31, 2013. As a percentage of sales, the average royalty rate for the three months and year ended December 31, 2014 decreased to 17%. This decrease was attributable to increased production from wells operated by the Company, which have lower royalty rates. As production from Divide County, North Dakota, increases, the Company expects the average companywide royalty rate to remain at approximately 18%, as this reflects the current royalty rates in Divide County, North Dakota, which is the source of 86% of the Company's production.

PRODUCTION TAXES

	Three months ended December 31		Year ended December 31	
($000's except per boe amounts)	2014	2013	2014	2013
Production taxes	451	800	2,126	1,631
Production taxes per boe	5.40	8.49	6.86	7.28
% of P&NG Sales	8.8%	10.8%	8.8%	7.9%

Production taxes are calculated as a percentage of revenues or volumes depending on the state laws of the producing assets and are payable to the state governments in Montana and North Dakota where Mountainview operates. For the quarter and year ended December 31, 2014, production taxes were $0.5 million and $2.1 million, respectively, or $5.40 per boe and $6.86 per boe, respectively. This compares favorably on a per boe basis to the quarter and year ended December 31, 2013, which saw production taxes of $8.49 per boe and $7.28 per boe, respectively. On a per barrel basis, this is 36% lower than the prior period quarter and 6% lower than the prior year.

OPERATING AND TRANSPORTATION COSTS

	Three months ended December 31		Year ended December 31	
($000's except per boe amounts)	2014	2013	2014	2013
Operating costs	2,947	1,372	8,909	4,935
Transportation costs	61	-	125	-
Total operating and transportation costs	3,008	1,372	9,034	4,935
Operating costs per boe	35.29	14.56	28.75	22.02
Transporation costs per boe	0.72	-	0.40	-
Total operating and transportation costs per boe	36.01	14.56	29.15	22.02

Operating and transportation expenses were $3.0 million or $36.01 per boe for the quarter ended December 31, 2014, compared to $1.4 million or $14.56 per boe for the quarter ended December 31, 2013. Operating and transportation expenses were $9.0 million or $29.15 per boe for the year ended December 31, 2014 as compared to $4.9 million or $22.02 per boe for the year ended December 31, 2013.

Management believes that Divide County operations reach optimal production with the use of an electric submersible pump (“ESP”) until the fluid levels have reduced to a level better managed by a Rotoflex artificial lift system. During the year ended December 31, 2014, a one-time successful fishing job occurred on three of the nine producing wells to replace the electric submersible pumps. These one-time operational expenses added to the current year’s operating expense increase.

As of December 31, 2014 six of the Company’s nine producing wells have been converted to a Rotoflex artificial lift system. One well was converted to a Rotoflex system in Q1, 2015. The remaining two wells will remain on ESPs until the fluid levels are reduced to a level better managed by the Rotoflex artificial lift system. These pump changes, combined with lower quarter over prior period quarter produced volumes have resulted in total, and per boe operating expenses that are 36% and 24% higher, respectively. The Company is actively pursuing cost reducing measures in an effort to decrease overall and per boe operating expenses going forward.

In efforts to reduce operating costs, the Company has entered into a contract with a local service provider to install salt water disposal lines which will flow the produced water to their existing salt water disposal well. The third party service provider has funded the installation of the water disposal lines. The installation of the salt water disposal system was completed in Q4, 2014 and is now operational. The agreement is expected to reduce the Company’s saltwater disposal costs by 50% going forward. The full impact of this project is expected to be realized in Q1, 2015 as all wells will be tied into this system for the entire quarter.

The Company has also successfully electrified the most recent well to come onto production at the end of Q4, 2014. This change is expected to reduce future operating costs in 2015 as the cost of generator fuel will be eliminated.

GENERAL AND ADMINSTRATIVE (“G&A”) EXPENSES

	Three months ended December 31		Year ended December 31	
($000's except per boe amounts)	2014	2013	2014	2013
G&A expense	1,041	786	3,281	2,220
Capitalized G&A expense	(79)	-	(285)	-
Net G&A	962	786	2,996	2,220
Total net G&A expense per boe	11.52	8.05	9.67	8.92

General and administrative expenses, net of recoveries and capitalized G&A, were $1.0 million or $11.52 per boe for the current quarter, and $3.0 million or $9.67 per boe for the year ended December 31, 2014. This is compared to $0.8 million or $8.05 per boe in the prior year comparative quarter and $2.2 million or $8.92 per boe in the year ended December 31, 2013. The Company’s expenses increased by 22% on a quarter over prior period quarter basis due to additional legal fees and travel associated with the marketing of the previously announced private placement financing. On a per boe basis, G&A has increased by $3.47 per boe or 43% over the prior period quarter, and $0.75 per boe, or 8% when comparing the year ended December 31, 2014 to the prior year. This increase is related to the financing activities and related expenses incurred by the Company in 2014.

Given the current commodity price environment and capital position of the Company, measures have been taken to reduce G&A going forward. The Company is expecting quarterly G&A for 2015 to be at or below $0.7 million per quarter.

SHARE-BASED PAYMENT EXPENSE

	Three months ended December 31		Year ended December 31	
($000's except per boe amounts)	2014	2013	2014	2013
Share based payment expense	73	114	391	529
Total per boe	0.87	1.06	1.26	1.75

During the three months ended December 31, 2014, the Company expensed $0.1 million in share-based payment expense as compared to $0.1 million in the three month period ended December 31, 2013.

The Company did not grant any options in 2014, but granted 750,000 options in 2013. Although no options were granted this year, the options granted in the prior years resulted in a share-based payment expense of $0.5 million. This decreased this year due to accounting treatment of the share-based payment expense recognizing more expense in earlier years than later years.

At December 31, 2014, the Company has 6,320,000 options outstanding, of which 5,072,778 had vested and were exercisable.

FINANCE EXPENSE

	Three months ended December 31		Year ended December 31	
($000's except per boe amounts)	2014	2013	2014	2013
Interest and bank charges	(5)	4	-	12
Interest on line of credit	104	73	508	427
Interest on long-term debt	9	1	25	5
Interest on credit facility	997	423	3,610	1,494
Finance costs on credit facility	80	601	217	601
Finance costs on line of credit	21	-	41	-
Interest on convertible debenture	22	22	88	88
Interest on promissory notes	199	217	793	770
Accretion on decommissioning liabilities	92	25	92	25
Accretion on credit facility	557	(114)	2,351	1,570
Total Finance expense	2,077	1,252	7,725	4,992
Total interest and accretion per boe	24.87	11.50	24.92	18.26

For the three months and year ended December 31, 2014, finance charges were $2.0 million and $7.7 million respectively as compared to $1.3 million and $5.0 million in the three months and year, respectively, ended December 31, 2013. This increase is due to increased bank debt for the quarter and year, which was $59.2 million compared to $46.9 million in the prior year quarter, interest on the promissory notes with a face value of $8.9 million, and interest on the convertible debentures with a face value of $2.1 million.

The Company's current interest charge on the credit facility is a floating rate with a minimum of 8.0%. The Company's promissory notes pay interest rates ranging from 5.0% to 9.0% and the convertible debentures pay an interest rate of 5.0% annually. The combined effective interest rate for the quarter was 7.1%.

DERIVATIVE ACTIVITIES

As part of the financial management strategy to protect cash flows available for capital expenditures, the Company has adopted a commodity price risk management program. The purpose of the program is to stabilize and hedge future cash flow against the unpredictable commodity price environment, with an emphasis on protecting downside risk. In Q4 2013, a direct wholly-owned subsidiary of Mountainview entered into an eighteen month

crude oil collar for January 2014 through June 2015 with a floor of $85.00 per barrel and a ceiling of $97.70 per barrel.

With derivative instruments, there is a risk that the counterparty could become illiquid or that Mountainview may not have the actual sales volumes to offset the hedge position. To manage risk, the Company's counterparties on derivative instruments are major international banks.

Realized gains and cash proceeds

The Company recognized a realized gain of $0.2 million ($2.55 per boe) and a realized loss of less than $0.1 million ($0.07 per boe) for the quarter and year, respectively, ended December 31, 2014. During the quarter, the realized gain was comprised of a $0.2 million loss on crude oil sales price derivatives. There were no hedges in place for the prior quarter comparative period.

Unrealized derivative assets and liabilities

The Company has recognized an unrealized gain on financial derivatives in the amount of $0.8 million ($9.91 per boe) and $1.0 million ($3.25 per boe) for the quarter and year, respectively, ended December 31, 2014. This unrealized gain is due to a decrease in forward WTI pricing in the second half of 2014.

The following is a summary of the derivative as at December 31, 2014:

	Three months ended December 31		Year ended December 31	
($000's except per boe amounts)	2014	2013	2014	2013
Realized gain (loss)	213	-	(21)	-
Unrealized gain (loss) - Financial derivatives	828	(127)	1,006	(127)
Gain (loss) and proceeds derivatives	1,041	(127)	985	(127)
Realized gain (loss) on derivatives per boe	2.55	-	(0.07)	-
Unrealized gain (loss) on derivatives per boe	9.91	(0.56)	3.25	(0.56)
Gain (loss) per boe	12.47	(1)	3.18	(1)

Crude Oil Sales Price Derivatives

As at December 31, 2014, there was an unrealized mark to market gain of $0.8 million (December 31, 2013 – $0.1 million loss) on this contract. The following table outlines the volumes hedged for the remainder of the contract:

Month	Monthly barrel (bbl) quantity
January 1, 2015	4,000
February 1, 2015	4,000
March 1, 2015	4,000
April 1, 2015	4,000
May 1, 2015	4,000
June 1, 2015	4,000

DEPLETION, DEPRECIATION & IMPAIRMENT

	Three months ended December 31		Year ended December 31	
($000's except per boe amounts)	2014	2013	2014	2013
Depletion & depreciation	1,851	1,772	6,217	6,000
Depletion & depreciation per boe	22.17	16.28	20.06	21.94

For the quarter and year ended December 31, 2014, depletion and depreciation of capital assets was $1.9 million ($23.27 per boe) and $6.2 million ($20.06 per boe), respectively. This is compared to $1.8 million ($16.28 per boe) and $6.0 million ($21.94 per boe) for the prior year's quarter and year end comparative periods, respectively. On an absolute basis, this quarter over prior period quarter increase relates to the increased value of oil and gas assets due to continued development activities. The rate per boe increased from the prior period quarter due to the decrease in reserve base at year end, 2014, and lower production in the quarter when compared to the prior year quarter. The increase in depletion, on an absolute basis, for the year over the prior year ended December 31 is a result of increased production for the year.

Exploration and evaluation costs are excluded from depletion until proved reserves are determined. At December 31, 2014, the Company assessed for indicators of impairment for all its exploration and evaluation assets. Reductions to long term forecast future oil, natural gas liquids, and natural gas benchmark pricing has impacted land sale values in Divide County. As such, the Company reviewed the carrying value of its undeveloped land in Divide County and it was determined that the asset value per acre was greater than the current or expected future value of acreage in Divide County. The carried net book value at December 31, 2014 for undeveloped acreage in Divide County was $4.0 million, while the estimated current value was $2.7 million. This resulted in an impairment charge of $1.3 million. In addition, due to the low realized commodity price environment, the Company does not have capital allocated for the development of the undeveloped acreage in the Stateline area, which straddles the border of Montana and North Dakota and the South Alberta Bakken area. As a result, this acreage is considered to be impaired. The Company is recognizing an impairment charge of $15.6 million relating to the undeveloped acreage in the Stateline and South Alberta Bakken area. This impairment charge represents the entire carried net book value of the undeveloped acreage in both areas. For more detailed disclosure regarding the impairment of exploration and evaluation assets, refer to Note 9 of the Company's audited December 31, 2014 financial statements.

At December 31, 2014, the Company reviewed the carrying value of the oil and gas properties by cash-generating units for indicators of possible impairment. As a result of the review, it was determined that the asset values of the oil and gas properties for Divide were greater than the value of the future reserves associated with those properties. The carried net book value at December 31, 2014 for Divide was $63.0 million, while the estimated recoverable amount was $40.1 million. This resulted in an impairment charge of $22.9 million. Increasing or decreasing the discount rate by 1% in the calculation of estimated recoverable amount would result in a change of $4 million on the overall impairment. Increasing the commodity price deck used in the impairment analysis by $5 used would reduce the impairment charge of $22.9 million by $7 million. Decreasing the commodity price deck by $5 would result in an additional impairment in Divide of $7.2M and the recognition of a $0.3 million impairment charge for the Legacy assets.

NET LOSS AND COMPREHENSIVE LOSS

The net and comprehensive loss for the quarter and year ended December 31, 2014 was $44.9 million ($0.51 per share) and $54.3 million ($0.62 per share) respectively. This is compared to a net and comprehensive loss of $3.1 million ($0.04 per share) and $6.0 million ($0.07 per share) for the quarter and year ended December 31, 2013. The net loss was mainly due to impairment of oil and gas assets and exploration and evaluation assets, decreased commodity price, increased financing expenses and increased operating expenses in the year ended December 31, 2014. See further discussion regarding increased operating expenses in the "Operating and Transportation Costs" section of this document.

	Three months ended December 31		Year ended December 31	
($000's except per share amounts)	2014	2013	2014	2013
Net Income (loss)	(44,899)	(3,141)	(54,347)	(5,974)
Net Income (loss) per share	(0.51)	(0.04)	(0.62)	(0.07)

QUARTERLY FINANCIAL SUMMARY

The following table highlights Mountainview's performance for each of the past eight quarters:

($000's except per share amounts)	Q4 2014	Q3 2014	Q2 2014	Q1 2014	Q4 2013	Q3 2013	Q2 2013	Q1 2013	Q4 2012
Average production (boe/d)	927	807	915	898	1,183	711	703	391	194
Petroleum and natural gas sales	5,108	5,883	7,010	6,108	7,418	5,993	5,107	2,009	778
Operating netback (per boe)(1)	9.17	28.83	35.42	34.56	34.39	26.13	24.98	24.12	(0.66)
Funds flow from operations(2)	(1,922)	(332)	(28)	310	2,085	2,156	766	(207)	150
Per share basic	(0.02)	(0.00)	(0.00)	0.00	0.02	0.02	0.01	(0.00)	(0.00)
Per share diluted	(0.02)	(0.00)	(0.00)	0.01	0.02	0.02	0.02	(0.00)	(0.00)
Net income (loss)	(44,899)	(1,638)	(6,267)	(1,561)	(3,141)	(387)	(1,065)	(1,381)	(7,344)
Per share basic	(0.51)	(0.02)	(0.07)	(0.02)	(0.00)	(0.01)	(0.02)	(0.02)	(0.08)
Per share diluted(3)	(0.51)	(0.02)	(0.07)	(0.02)	(0.00)	(0.01)	(0.02)	(0.02)	(0.08)
Capital expenditures(4)	3,669	7,403	6,333	7,910	16,584	7,262	1,682	21,401	6,489
Total assets	54,979	101,208	86,800	90,214	84,744	74,265	67,253	65,131	49,056
Net debt excluding financial derivatives(5)	84,658	75,911	71,304	65,314	59,244	46,883	35,772	33,287	19,804

(1) Operating netback is a non-GAAP measure calculated as the average per boe of the Company's oil and gas sales plus realized gains on derivatives, less royalties, operating and transportation expenses.

(2) Funds flow from operations should not be considered an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with International Financial Reporting Standards as an indicator of Mountainview's performance. Funds flow from operations represents cash flow from operating activities prior to changes in non-cash working capital, transaction costs and decommissioning provision expenditures incurred. Mountainview also presents funds flow from operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of earnings per share.

(3) Due to the anti-dilutive effect of Mountainview's net loss for the three months and year ended December 31, 2013 and 2012, the diluted number of shares is equal to the basic number of shares. Therefore, diluted per share amounts of the net loss are equivalent to basic per share amounts.

(4) Capital expenditures is a non-GAAP measure, calculated as the purchase or sale price of an asset, plus development capital expenditures added to PP&E. Corporate acquisitions are excluded from this measure.

(5) Net debt is a non-GAAP measure representing the total of bank indebtedness, accounts payables and accrued liabilities, less accounts receivables, deposits and prepaid expenses.

Quarterly variances in sales are connected to changes in production volumes and prices. In Q1 2014, the Company added production volumes with the completion and tie-in of two wells. In Q4 2014, average daily production was 927 boe/d. The production profile of a Three Forks (Torquay) well demonstrates initial flush production rates, with a significant decline in the first months of the production life. The production rate then stabilizes and the wells produce for an extended reserve life with relatively low decline rates. In Q4 2013 and Q1 2014, the Company realized these expected declines from initial production rates on six of the nine wells operated by the Company in addition to increased operating expenses. See further discussion regarding increased operating expenses in the "Operating and Transportation Costs" section of this document. While the Company worked to minimize the production interruptions, various wells were still intermittently shut in for short periods of time. The conversion of wells to a Rotoflex pumping unit and the ninth well coming on line has contributed to the increased average daily production rate for the quarter ended December 31, 2014. This production increase was offset by weaker commodity prices in Q4 2014, impacting sales revenue.

Through its strategy to protect cash flows, a direct wholly-owned subsidiary of Mountainview hedges a percentage of production using financial derivatives. As such, commodity price swings in oil have a moderated effect on funds flow from operations, as only current quarter realized cash gains or losses are included. Funds

flow from operations grew with production throughout 2012 and 2013 as production increased from drilling operations in Divide County, North Dakota. This increase in production was accompanied by an increase in produced water, and also required pump changes to optimally handle the expected long term fluid levels. In future, the Company expects improvements in per boe operating expenses as the installation of new Rotoflex pumps will require fewer workovers and have a lower per boe operating cost. Currently, six of nine producing wells operated by the Company have been converted to the Rotoflex pump. The increased operating expenses resulted in decreased funds flow from operations in Q4 2014 when compared to Q3 2014. See further discussion regarding increased operating expenses in the “Operating and Transportation Costs” section of this document.

Quarterly variances in net income, however, are largely driven by commodity price variance, financing costs and non-cash items, such as depletion, impairment, lease expiries, and unrealized gains or losses on derivatives. The Company funded its initial eight well program with debt, resulting in increased financing expenses as wells were drilled and completed. The net loss in Q4, 2014 was largely due to impairment charges, financing costs, and lower realized oil prices, further compounded by increased operating expenses further discussed in the “Operating and Transportation Costs” section of this document.

FUNDS FLOW FROM OPERATIONS AND NETBACKS

Funds flow from operations is a non-GAAP measure. Funds flow from operations represents cash flow from operating activities adjusted for changes in non-cash operating working capital. Mountainview considers this to be a key measure of performance as it demonstrates the Company’s ability to generate the cash flow necessary to fund capital investment and ultimately, satisfy corporate strategy.

	Three months ended December 31		Year ended December 31	
($000's except per share amounts)	2014	2013	2014	2013
Cash flow from operating activities	5,774	4,043	(1,961)	5,384
Change in non-cash working capital	(7,103)	(5,072)	582	(2,025)
Funds flow(1)	(1,329)	(1,029)	(1,379)	3,359
Funds flow per share	(0.02)	(0.01)	(0.02)	0.04

(1) Funds flow from operations is a non-GAAP measure that represents cash provided by operating activities, before adjusting for changes in non-cash working capital items and expenditures on decommissioning liabilities.

Mountainview’s corporate strategy aims to provide shareholders with long term total returns comprised of appreciation of share value, with a focus on production and reserve growth. Funds flow from operations for the quarter and year ended December 31, 2014 were $(1.3) million ($(0.02) per share) and $(1.3) million ($(0.02) per share), respectively. This is a decrease from the fourth quarter 2013 funds flow of $(1.0) million ($(0.01) per share), and $3.4 million ($0.04 per share) for the year ended December 31, 2013 due to a decrease in commodity pricing and an increase in operating expenses. See further discussion regarding increased operating expenses in the “Operating and Transportation Costs” section of this document.

On a per boe basis, Mountainview’s operating netbacks have decreased in Q4, 2014, as the realized price for product sales has decreased on a quarter over quarter basis, while operating expenses have increased. See further discussion regarding increased operating expenses in the “Operating and Transportation Costs” section of this document.

The following table summarizes netbacks for the past eight quarters on a barrel of oil equivalent basis:

($ per boe)	Q4 2014	Q3 2014	Q2 2014	Q1 2014	Q4 2013	Q3 2013	Q2 2013	Q1 2013	Q4 2012	Q3 2012
Petroleum and natural gas sales	61.16	82.40	91.06	75.01	68.16	83.47	73.72	66.45	54.98	58.01
Royalties	(10.58)	(16.84)	(14.99)	(13.02)	(13.49)	(12.96)	(11.57)	(7.77)	(5.62)	(2.77)
Production and operating expense	(41.41)	(36.73)	(33.71)	(27.43)	(20.08)	(26.57)	(29.73)	(21.40)	(36.94)	(20.84)
Operating netback [(1)]	9.17	28.83	42.36	34.56	34.59	43.94	32.42	37.28	12.42	34.40
General and administrative expense	(11.52)	(10.05)	(8.05)	(7.80)	(8.05)	(5.25)	(7.72)	(16.43)	(36.94)	(20.84)
Interest and bank charges	(24.87)	(23.54)	(25.77)	(21.98)	(11.50)	(28.21)	(15.89)	(24.95)	(6.28)	(8.19)
Funds flow from operations [(2)]	(27.21)	(4.76)	8.54	4.78	15.04	10.48	8.81	(4.10)	(30.80)	5.37

(1) Operating netback is a non-GAAP measure calculated as the average per boe of the Company's oil and gas sales, realized gains (losses) on derivatives, less royalties, operating and transportation expenses.

(2) Funds flow from operations is a non-GAAP measure that represents the total of funds provided by operating activities, before adjusting for changes in non-cash working capital items and expenditures on decommissioning liabilities.

CAPITAL EXPENDITURES AND PP&E ADDITIONS

	Year ended December 31	
($000's)	**2014**	**2013**
Land acquisition	643	2,102
Geological and geophysical	13	-
Drilling and completions	18,642	26,238
Equipping and facilities	4,304	2,494
Other	-	506
Development capital	23,602	31,340
Property dispositions - cash received	(400)	-
Capital expenditures	23,202	31,340
Net other additions to PP&E	351	17,367
Total net additions to PP&E	23,553	48,707

(1) Capital expenditures is a non-GAAP measure and is defined as the total cash consideration paid or received for property acquisitions and dispositions, plus development and exploration capital expenditures. This measure is used by management to calculate the Payout and Total Payout Ratios.

(2) Net other additions to PP&E reconciles the Non-GAAP Capital Expenditures measure to the IFRS measure of capital additions, and is the net adjustments made to account for the assets purchased under IFRS 3 - Business Combinations, assets sold for cash, reclassification of E&E assets, and corresponding changes in PP&E due to changes in the decommissioning liability.

During the year ended December 31, 2014, the Company invested $23.2 million on development capital, a decrease from $31.3 million in development capital invested in 2013. The Company's development capital expenditures for the year ended December 31 were focused in Divide County, with successful drilling of 3 (1.3 net) oil wells.

Mountainview plans to complete the two remaining standing wells as soon as capital becomes available and the commodity price improves. The Company plans to finance continued development operations from its continued efforts to close the previously announced equity offering. The budgeted gross cost for completion operations is $1.8 million per well ($1.2 million net). Management considers these expenditures to be discretionary.

Drilling Results

Year ended December 31	2014		2013	
	Gross	Net	Gross	Net
Crude Oil	3.0	1.3	8.0	4.8
Dry and abandoned	-	-	-	-
Total	3.0	1.3	8.0	4.8
Success Rate %		100%		100%

Undeveloped Land

	At December 31 2014	At December 31 2013
Gross Acres	63,808	106,535
Net Acres	41,239	58,411

The Company's undeveloped land holdings have decreased from December 31, 2013, as acreage expiries were recognized in non-core areas and an impairment charge of $16.8 million was recorded in the 2014 year end financials. See further discussion of the impairment factors assessed as discussed earlier in the "Depletion, Depreciation & Impairment" section of this document.

The table below outlines the timing of future expirations of the remaining undeveloped Divide County acreage if drilling in the area does not continue.

	Net Acres
2015 Expirations	13,444
2016 Expirations	14,131
	27,575

LIQUIDITY AND CAPITAL RESOURCES

The Company's objective when managing capital is to maintain a conservative, yet flexible structure which will allow it to execute on its capital program. The Company actively monitors its capital structure through cash flow from operating activities before changes in non-cash working capital, which drives current and forecasted net debt levels. In forecasting these amounts, the Company includes economic conditions; investment opportunities; past and forecasted capital investment efficiencies; and current and forecasted petroleum and natural gas prices.

In order to manage the capital structure, the Company will focus on its forecasted debt to forecasted cash flow from operating activities (before changes in non-cash working capital) ratio; the current level of available credit under the bank facility; the level of bank credit that may be obtainable as a result of crude oil and natural gas reserve growth; the availability of other sources of debt; issuing new common equity if available on favorable terms; the sale of assets; and limiting the size of the investment program.

The Company's share capital is not subject to external restrictions; however, its credit facility value is based primarily on its petroleum and natural gas reserves and there are covenants Mountainview must comply with which are detailed below. The Company was not in compliance with all of its debt covenants at the end of the reporting period, see further discussion below regarding covenant breaches by debt instrument. The Company confirms there are no off-balance sheet financing arrangements.

Line of Credit

On April 17, 2012, the Company entered into a revolving line of credit for $5,500,000 and on June 27, 2012, increased the line of credit to $8,700,000. During the year ended December 31, 2014, the line of credit was converted to a term loan extending the maturity date from October 17, 2014 to November 1, 2015. The outstanding balance at December 31, 2014 was $8,660,000. The Company's US subsidiary provided a general security over its assets as collateral for the line of credit and, a director and officer of the Company and major shareholder have provided personal guarantees. Carrying value of the collateral at December 31, 2014 was $4,060,588. The minimum interest rate is 5.25%. Repayment terms are monthly principal and interest payments of $110,900. At December 31, 2014 the Company was in default due to nonpayment of a lump sum principal payment due December 1, 2014. The Company has also not made payments on the loan in the months of February and March 2015. At this time the bank has not taken any formal action to exercise its rights and/or remedies under the credit agreement, nor has it applied the Default Rate. The Company continues to communicate and cooperate with the bank to rectify the defaults, allowing management to propose a comprehensive solution.

Convertible debenture

On May 28, 2012, the Company acquired from a related company, a compressor, plant and equipment for consideration of $2,660,000. The Company paid $283,000 and agreed to issue a $2,377,000 debenture convertible into common shares of the Company at a price of $2.50 per common share (the actual convertible debenture issued was $2,072,053, which was reduced by costs incurred of $304,947 on behalf of the related company prior to the transaction closing). During the year ended December 31, 2013 the original Convertible Debenture was cancelled and a new Convertible Debenture was signed to extend the maturity date to June 1, 2015. In the year ended December 31, 2014 an amendment to the debenture was issued extending the maturity date to July 1, 2016 all other terms remained unchanged. At December 31, 2014 the convertible debenture was $2,072,053 plus accrued interest of $227,756. Principal and interest payments are due at maturity. At December 31, 2014, if the convertible debenture had been converted the Company would have issued 919,924 additional common shares.

Credit Facility

The Company entered into a senior secured advancing credit facility (the "Facility") for up to a maximum of $75.0 million. At December 31, 2014 the Company had $51.8 million drawn with no additional funds available on this facility. The Facility matures on July 1, 2015, and amounts borrowed bear interest at a floating rate with an 8% minimum. Monthly repayments of outstanding interest plus principal are required based on 85% of net profits from the 12-Gage Project. In connection with the Facility, the lender and the Company will have an area of mutual interest ("AMI"), which will be in northern Divide County, North Dakota. In addition, pursuant to the Facility, upon the earlier of the maturity date or the date the Facility is paid in full, the Lender will trigger the start of a 39% after pay-out net profits interest (the "NPI") in all of the Company's oil and gas properties within Divide County, North Dakota.

The NPI is defined as all revenues, less all operating costs, production taxes, and capital costs incurred by the Company. Payments on the NPI commence upon repayment in full of the outstanding Facility. The NPI will be reduced from 39% to 20% once the lender achieves a 0.65 x return on investment. Return on investment is based on principal plus interest and fees. At December 31, 2014 the return on investment required to trigger this reduction in NPI is $36.9 million. The Facility is secured by a first priority mortgage and security interest in the 12-Gage properties. The carrying amount of the collateral is $49,593,105. The borrowing base under the Facility will be subject to re-determination in the absolute discretion of the lender. The Company's US subsidiary, Mountain Divide LLC, is required to maintain a current ratio of 1.0: 1.0. At December 31, 2014 the US subsidiary's current ratio excluding the credit facility balance was 0.41:1.0, which results in a covenant breach.

For the year ended December 31, 2014, the Company incurred fees of $61,591 representing 1.25% of the borrowing base increase to the lender. A finder's fee was also incurred in conjunction with Facility. The finder's fee is payable at a rate of 4% based on each borrowing base increase up to the total amount available of $75.0 million, $1.31 million was accrued at December 31, 2014.

During the year ended December 31, 2014, the Company received proceeds of $13,218,423 (December 31, 2013 $38,575,824) under the Facility. The transaction has been recorded as a borrowing and a sale of conveyance relating to the 20% NPI. The Company has determined the fair value of the conveyance portion of the arrangement using a relative percentage of the conveyed property's fair value determined at its acquisition date and has recorded this amount of $2,661,399 (December 31, 2013 - $2,810,249) as an adjustment to the property. The residual amount of the initial proceeds has been determined to be a borrowing and has been recorded as a current liability based upon the expected terms of repayment. The discount to the face amount of the debt will be accreted over the term of the Facility. At December 31, 2014, the Company owed $49,394,474 under the Facility. During the year ended December 31, 2014, the Company has repaid $3,107,389 of the principal and has paid or accrued $3,609,824 in interest.

As noted above, at December 31, 2014 the Company is in default due to the following covenant breaches (1) the current ratio covenant (2) the covenant which requires prompt and timely payment of trade vendors and (3) the covenant requiring all oil and gas assets to be free of liens (Note 25). The lender has been notified of these breaches and is working with management towards a comprehensive solution. At this time the bank has not taken any formal action to exercise its rights and/or remedies under the credit agreement nor has it applied the Default Rate. The Company continues to communicate and cooperate with the bank to rectify the defaults, allowing management to propose a comprehensive solution.

The following table reconciles the face value of the credit facility to the carrying value:

	December 31, 2014	December 31, 2013
Balance, beginning of period	$ 38,203,410	$ 1,004,308
Proceeds received	13,218,423	38,575,824
Principal payments	(3,107,389)	(3,175,455)
Conveyance Fee	148,850	(187,336)
Accretion	2,350,825	1,569,632
Amortization of deferred finance costs	-	141,449
Interest accrual(payment)	(274,987)	274,988
Balance, end of period	**$ 50,539,132**	**$ 38,203,410**

Long-term debt

The Company has various vehicle loans outstanding as of December 31, 2014 and December 31, 2013 with balances of $391,042 and $391,167, respectively. The current portion of vehicle loans as at December 31, 2014 and December 31, 2013 is $126,319 and $109,187. There are twelve vehicle loans with fixed rates that vary from 0% interest to 3.90% and will be repaid after five years.

Promissory notes

The Company entered into two unsecured promissory notes payable with major shareholders of the Company, each for $4,000,000 (total $8,000,000), bearing interest at 9% per annum and drawdown of the full principal balance. The principal was payable on or before May 30, 2015. During the year ended December 31, 2014, amendments to the promissory notes were executed extending the maturity to July 1, 2016. At December 31, 2014, the balance due on the promissory notes was $7,850,000 plus accrued interest of $1,632,144. Principal and interest payments are due at maturity.

On March 12, 2013, the Company entered into two unsecured promissory notes payable with major shareholders of the Company and a Company with a director and officer in common, for $250,000, bearing interest at 5% per annum. The principal was payable on or before March 12, 2015. During the year ended December 31, 2014, amendments to the promissory notes were executed extending the maturity to July 1, 2016. At December 31, 2014, the balance due on the promissory notes is $250,000 plus accrued interest of $22,964. Principal and interest payments are due at maturity.

On November 26, 2013, the Company signed three unsecured promissory notes payable with a major shareholder of the Company, for $460,949, $248,205, and $96,000, bearing interest at 9% per annum. The principal was payable on or before March 15, 2015, May 7, 2015 and June 6, 2015. During the year ended December 31, 2014, amendments to the promissory notes were executed extending the maturity to July 1, 2016. At December 31, 2014, the balance due on the promissory notes is $805,154 plus accrued interest of $129,759. Principal and interest payments are due at maturity.

The following is a schedule of debt payments over the next five years:

At December 31, 2014	Total	< 1 Year	1-3 years	4-5 years	After 5 years
Credit facility	$ 50,539,132	$ 50,539,132	$ -	$ -	$ -
Line of credit	8,660,000	8,660,000	-	-	-
Promissory notes	10,690,020	-	10,690,020	-	-
Convertible Debenture	2,299,809	-	2,299,809	-	-
Vehicle loans	391,042	126,319	259,753	4,970	-
Total contractual obligations	$ 72,580,003	$ 59,325,451	$ 13,249,582	$ 4,970	$ -

SHARE CAPITAL

In the fourth quarter of 2014, there were no shares issued on account of vested share purchase options that were exercised, nor were any shares issued on account of vested share purchase options that were exercised in the first quarter of 2013.

As of April 16, 2014 the Company has 87,820,443 Common Shares, 6,320,000 stock options and 7,822,727 class B shares in a subsidiary outstanding. The Class B shares can be exchanged at the option of the holder, on a share for share basis with common stock of the Company or, at the option of the Company, be paid by cash at the current market value calculated as weighted average price per common stock of the Company for 20 consecutive trading days of the TSX-V. The exchange dates are as follows:

- September 4, 2012 to June 4, 2013 33%
- September 5, 2013 to June 5, 2014 66%
- September 6, 2014 to June 7, 2019 100%
- September 8, 2019 to June 9, 2022 100% (mandatory exchange or payable by cash)

The effect of Class B shares has not been included in the EPS for the periods ended December 31, 2014 and 2013. As at December 31, 2014 none of the shares have been exchanged.

In addition, there is a convertible debenture outstanding which, if converted at December 31 2014, would have resulted in the issuance of 919,924 Common Shares.

CONTRACTUAL OBLIGATIONS AND CONTINGENCIES

The Company enters into short term contractual obligations in the normal course of business, including purchase of assets and services, operating agreements, transportation commitments, sales commitments, royalty obligations, lease rental obligations and employee agreements. These obligations are of a recurring, consistent nature and impact cash flows in an ongoing manner.

Mountainview also has long-term contractual obligations and commitments. The Company is responsible for the retirement of long-lived assets related to its oil and gas properties at the end of their useful lives. Mountainview has recognized a liability of $2.5 million (December 31, 2013 – $1.2 million) based on current legislation and estimated costs. Actual costs may differ from those estimated due to changes in legislation or actual costs.

Additional contractual obligations and commitments are as follows:

At December 31, 2014	< 1 Year	1-3 years	3-5 years	After 5 years	Total
Trade and accrued liabilities	$ 18,988,006	$ -	$ -	$ -	$ 18,988,006
Line of credit[1]	8,660,000	-	-	-	8,660,000
Long-term debt	126,319	259,753	4,970	-	391,042
Credit facility - principal[1]	49,459,290	-	-	-	49,459,290
Convertible debenture - principal[2]	2,072,053	-	-	-	2,072,053
Convertible debenture - interest	227,756	-	-	-	227,756
Promissory notes - principal	-	8,935,154	-	-	8,935,154
Promissory notes - interest	-	1,754,867	-	-	1,754,867
Total	$ 79,533,424	$ 10,949,774	$ 4,970	$ -	$ 90,488,168

(1) Repayment of this principal amount in less than one year is based on the terms of the credit agreement.
(2) Repayment of the Convertible Debentures assumes that all holders of the debentures will not convert their holdings into shares.

RELATED PARTY TRANSACTIONS

During the year ended December 31, 2014 the Company paid or accrued $6,576,147. (December 31, 2013 $5,619,250) to five companies owned by one of its major shareholders for services provided in the drilling and operating of the wells in the 12-Gage Project. These services have occurred in the normal course of business and are measured at their exchange amount. On January 23, 2015 all five companies had filed liens on the Company's oil and gas assets in the total amount of $1,140,484. The Company continues to receive revenues despite the liens filed, see Note 25.

During the year ended December 31, 2014, the Company had a joint interest receivable of $76,048 (December 31, 2013 $351,097) from two companies owned by two of its major shareholders. The companies are participants in certain joint venture activities.

During the year ended December 31, 2014, the Company had net a joint interest receivable of $21,031 and had paid or accrued $48,577 (December 31, 2013 - $60,774 and $Nil) from/to three companies owned by a Director and officer in common. The companies are participants in certain joint venture activities.

As of December 31, 2014 the Company executed a purchase and sale agreement for one of the company's non- operated oil and gas assets with a company owned by a major shareholder. Sales proceeds were $400,000 and a loss of $269,149 was recognized on the disposal.

Key management includes the Company's directors and officers. Compensation awarded to key management includes salaries and benefits including director fees, consulting fees and awards granted under the Company's long-term incentive plan.

The following table presents key management compensation at December 31, 2014:

Key management compensation:		2014		2013
Salaries, benefits and other short term compensation	$	893,000	$	583,686
Share-based compensation		234,476		343,995
Total key management compensation	**$**	1,127,476	**$**	927,681

ASSESSMENT OF BUSINESS RISKS

The following are the primary risks associated with the business of Mountainview. These risks are similar to those affecting other companies competing in the conventional oil and natural gas sector. Mountainview's financial position and results of operations are directly impacted by these factors and include:

Operational risk associated with the production of oil and natural gas:

- the ability of the corporation to continue operating as a going concern
- continued participation of Mountainview's lenders despite debt covenant breaches. Mountainview seeks to mitigate these risks by:
    - acquiring properties with established production trends to reduce technical uncertainty as well as undeveloped land with development potential;
    - maintaining a low cost structure to maximize product netbacks and reduce impact of commodity price cycles;
    - diversifying properties to mitigate individual property and well risk;
    - maintaining product mix to balance exposure to commodity prices;
    - conducting rigorous reviews of all property acquisitions;
    - monitoring pricing trends and developing a mix of contractual arrangements for the marketing of products with creditworthy counterparties;
    - maintaining a hedging program to hedge commodity prices with creditworthy counterparties;
    - adhering to the Company's safety program and adhering to current operating best practices;
    - keeping informed of proposed changes in regulations and laws to properly respond to and plan for the effects that these changes may have on our operations;
    - carrying industry standard insurance;
    - establishing and maintaining adequate resources to fund future abandonment and site restoration costs; and
    - monitoring our joint venture partners' obligations to us and cash calling for capital projects to limit the Company's credit risk.
- commodity risk as crude oil and natural gas prices fluctuate due to market forces;
- the ability of the Company to obtain new funding to meet the funding requirements of future capital programs which would be needed to ensure cash flow from reserves will be sufficient to cover ongoing activities
- the Company's level of indebtedness reduces financial flexibility
- reserve risk in respect to the quantity and quality of recoverable reserves;
- exploration and development risk of being able to add new reserves economically
- market risk relating to the availability of transportation systems to move the product to market;
- financial risk such as volatility of the Canadian/U.S. dollar exchange rate, interest rates and debt service obligations;
- environmental and safety risk associated with well operations and production facilities;

- changing government regulations relating to royalty legislation, emissions, income tax laws, incentive programs, drilling and operating practices and environmental protection relating to the oil and natural gas industry
- fluctuations in the Company's market price per share or potential dilution resulting from any future acquisitions or financings
- litigation, in the normal course of operations, the Company may be come party to or be the subject of legal proceedings.
- breach of confidentiality, while discussing potential business relations or transactions with third parties the Company may disclose confidential information.
- management growth, can management continue to grow its internal systems as needed and retain key personnel to ensure proper controls and financial systems are in place at all times

Please also see the risk factors identified in Mountainview's annual information form, which is available on SEDAR.

CRITICAL ACCOUNTING JUDGEMENTS, ESTIMATES AND ACCOUNTING POLICIES

For more details regarding the Company's critical accounting judgments, estimates and accounting policies the following should be read in conjunction with the Company's 2014 audited financial statements.

Management is required to make judgments, estimates and assumptions in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from those estimates and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. The Company's critical accounting policies and estimates are reviewed annually by the Audit Committee of the Board of Directors of the Company. Further details on the basis of presentation and significant accounting policies can be found in the Company's notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2014.

Critical Accounting Judgments in Applying Accounting Policies

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recognized in the Company's annual and interim Consolidated Financial Statements and accompanying notes. On January 1, 2014, as required, the Company adopted the amendments to IAS 32 and IFRIC 21. See discussion below under Changes in Accounting Policies for details. Further information on Management's critical accounting judgments in applying accounting policies can be found in the notes to the Consolidated Financial Statements for the year ended December 31, 2014.

Critical accounting estimates

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recognized in the period in which the estimates are revised. For 2014, the Company had a change in estimate related to its depletion calculation, see Note 5 in the Consolidated Financial Statements for the year ended December 31, 2014.

Changes in Accounting Policies

The Company adopted several new IFRS interpretations and amendments in accordance with the transitional provisions of each standard. A brief description of each new accounting policy and its impact on the Company's financial statements follows below:

- IAS 32 Financial Instruments: Presentation — The Company adopted, as required, amendments to IAS 32. The amendments clarify that the right to offset financial assets and liabilities must be available on the current

date and cannot be contingent on a future event. IAS 32 did not impact the Company's interim financial statements.

- IAS 36 "Impairment of Assets" has been amended to reduce the circumstances in which the recoverable amount of cash generating units "CGUs" is required to be disclosed and clarify the disclosures required when an impairment loss has been recognized or reversed in the period. The retrospective adoption of these amendments will only impact the Company's disclosures in the notes to the financial statements in periods when an impairment loss or impairment reversal is recognized.

- IAS 39 "Financial Instruments: Recognition and Measurement" has been amended to clarify that there would be no requirement to discontinue hedge accounting if a hedging derivative was novated, provided certain criteria are met. The retrospective adoption of the amendments does not have any impact on the Company's financial statements.

- IFRIC 21 "Levies" was developed by the IFRS Interpretations Committee ("IFRIC") and is applicable to all levies imposed by governments under legislation, other than outflows that are within the scope of other standards (e.g., IAS 12 "Income Taxes") and fines or other penalties for breaches of legislation. The interpretation clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. It also clarifies that a levy liability is accrued progressively only if the activity that triggers payment occurs over a period of time, in accordance with the relevant legislation. Lastly, the interpretation clarifies that a liability should not be recognized before the specified minimum threshold to trigger that levy is reached. The retrospective adoption of this interpretation has had a nominal impact on the Company's financial statements.

Future Accounting Pronouncements

Financial Instruments

IFRS 9, Financial Instruments, was issued in July 2014 and is intended to replace IAS 39, Financial Instruments: Recognition and Measurement, and uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39, and incorporates new hedge accounting requirements. IFRS 9 is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. The Company is in the process of assessing the impacts of adopting this new standard. In May 2014, the IASB issued IFRS 15 Revenue from Contracts with Customers, this standard will replace IAS 18 Revenue, IAS 11 construction contracts, and related interpretations. The standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2017, with earlier adoption permitted. The company is currently evaluating the impact of the standard on the financial statements.

Revenue

In May 2014, the IASB issued IFRS 15, Revenue from Contracts with Customers, which replaces IAS 18, Revenue, IAS 11, Construction Contracts, and related interpretations as the single source for accounting for revenue for all companies in all industries and replaces current guidance including industry or product specific guidance. IFRS 15 provides specific and detailed guidance in many areas where current standards have been more limited, and thus may provide for less flexibility in developing and applying accounting policies and practices. This standard is required to be adopted either retrospectively or using a modified transition approach and is effective for annual periods beginning on or after January 1, 2017, with earlier adoption permitted. The Company is in the process of assessing the impacts of adopting this new standard.

Subsequent Events

Subsequent to the year ended December 31, 2014, due to the low commodity price environment and its impact on cash flow, a direct wholly-owned subsidiary of the Company has been unable to pay the outstanding vendors in a timely manner. As a result, some vendors have filed liens on the subsidiary's producing wells. At present, the subsidiary continues to receive all of its revenue from these wells, with the exception of a one-time sum of $27,000, which has been withheld by the purchaser of the subsidiary's produced oil. This sum is withheld under the terms of one lien, and will be held by the purchaser until the legal documentation has been received from the vendor to release the funds. Upon receipt of the legal documentation, and release of funds, this lien will be cleared. Management is in regular communication with all vendors and the vendors continue to work with the subsidiary, allowing management time to find a solution to the outstanding payable balance owed. From December 31, 2014 through April 30, 2015, the subsidiary had $7.2 million in liens placed on its producing oil and gas assets.