HILLCREST PETROLEUM LTD.

(Formerly Hillcrest Resources Ltd.)

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the Year Ended December 31, 2014

Report Date - April 30, 2015

This Management's Discussion and Analysis ("MD&A") is provided by the management of Hillcrest Petroleum Ltd. ("Hillcrest" or the "Company") as at and for the year ended December 31, 2014. The commentary in this MD&A is based on information available up to the Report Date.

This MD&A should be read in conjunction with the Company's audited annual consolidated financial statements for the years ended December 31, 2014 and 2013. All amounts are in Canadian dollars unless otherwise specified.

Additional information relating to the Company, including the audited annual consolidated financial statements for the years ended December 31, 2014 and 2013 are available on the Hillcrest website at **www.hillcrestpetroleum.com** or on the Canadian System for Electronic Document Analysis and Retrieval ("SEDAR") website at **www.sedar.com.**

Forward-Looking Statements

The MD&A, which contain certain forward-looking statements, is intended to provide readers with a reasonable basis for assessing the financial performance of the Company. The use of any of the words "believe", "expect", "estimate", "will", "should", "intend" and similar expressions are intended to identify forward-looking statements. Forward-looking statements are necessarily based upon a number of estimates and assumptions that, while considered reasonable by the Company, are inherently subject to significant business, economic and competitive uncertainties and contingencies. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such risks include, but are not limited to, fluctuations in the currency markets such as the Canadian and US dollar, fluctuations in the commodity price of oil and natural gas, changes in government legislation, taxation, controls, regulations and political or economic developments in Canada and the United States or other countries in which the Company carries or may carry on business in the future, the speculative nature of exploration and development in the oil and gas industry, including the risk of obtaining necessary licenses and permits, and the quantities or estimation of reserves. The Company believes these expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward looking statements included herein should not be unduly relied upon. Actual results and developments may differ materially from those contemplated by the forward looking statements. The forward-looking information contained in this MD&A represents our expectations as of the date of this MD&A and, accordingly, is subject to change after such date. We expressly disclaim any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by applicable law.

Overview

PRINCIPAL BUSINESS AND CORPORATE HISTORY

Hillcrest Petroleum Ltd. was incorporated under the Company Act (British Columbia) on May 2, 2006 and on May 28, 2007 the Company changed its name from Shanghai Creek Minerals Ltd. to Hillcrest Resources Ltd. The Company listed its common shares for trading on the TSX Venture Exchange (the "Exchange") and commenced trading under the symbol "HRH" on March 22, 2011. On March 11, 2015, the Company changed its name to Hillcrest Petroleum Ltd.

The Company is in the business of acquiring and developing exploration and producing interests in oil and gas projects in the United States of America.

The Company is subject to several categories of risk associated with the exploration for and production of oil and gas. Oil and gas exploration and production is a speculative business, and involves a high degree of risk and uncertainty. Among the factors that have a direct bearing on the Company's prospects are exploration and development risk as well as uncertainties inherent in estimating oil and gas reserves, future hydrocarbon production and cash flows, particularly with respect to wells that have not been fully tested and with wells having limited production histories; access to additional capital; changes in the price of oil and gas; availability and cost of services and equipment; and the presence of competitors with greater financial resources and capacity.

The oil and gas industry is subject, by its nature, to environmental hazards and clean-up costs. At this time, management knows of no substantial costs from environmental accidents or events for which the Company may be currently liable. In addition, the Company's oil and gas business makes it vulnerable to changes in prices of crude oil and natural gas. Such prices have been volatile in the past and can be expected to be volatile in the future. By definition, proved reserves are based on estimated future oil and gas prices and costs. Price declines reduce the estimated quantity of proved reserves and increase annual depletion expense (which is based on proved and probable reserves).

Management and consultants of the Company have extensive experience in oil and gas exploration, development and production and have the capability to expand the scope of the Company's activities as appropriate opportunities arise. Since the Company's founding on May 2, 2006, the Company has acquired seed funding, put in place an operational structure, set up offices in Vancouver, British Columbia, and Houston, Texas and engaged key exploration and land personnel, and added to its initial oil and natural gas assets and associated equipment by raising capital via equity placements, debt facilities and internally generated funds.

OIL AND GAS PROPERTIES

Hillcrest currently has interests in the following significant oil and gas properties:

a) Hartburg Project, Texas

By agreement dated December 8, 2009, the Company entered into an Assignment and Assumption Agreement for the assignment of a 60% working interest in certain oil and gas leases known as the Hartburg Project in Newton County, Texas. In consideration the Company paid a lump sum of $117,040 (US $111,266). The Company is responsible for its proportionate share of all future costs of the development of the property.

On March 27, 2009, Barry Lasker ("Lasker") and Delta Oil and Gas, Inc. ("Delta") entered into an exploration agreement (the "Exploration Agreement"). Pursuant to the terms of the Exploration Agreement, Lasker agreed to identify and secure leases which would subsequently be assigned to Delta and pursuant to the terms of such agreement, Delta agreed to pay 100% of the lease acquisition costs and operating costs of up to three wells. In exchange for Lasker's performance under the Exploration Agreement, Lasker obtained a 10% carried interest in the first target well, Donner #1, and a 20% carried interest in the second and third target wells, Prospect 1 (Donner #2) and Prospect 2 (Donner #4), respectively, until payout in each of the wells. Upon payout, Lasker's carried interest converted to a 50% working interest in Donner #1 and a 40% working interest in each of Prospect 1 and Prospect 2.

In August 2009, Donald Currie in his personal capacity and not in his capacity as an officer or director of the Company, entered into an oral agreement with Lasker which is evidenced by a written agreement dated January 10, 2010 to acquire 50% of all of Lasker's right, title and interest in and to the Exploration Agreement.

On December 30, 2010, Delta entered into an agreement (the "HRI Assignment") with the Company to assign 60% of all of Delta's right, title and interest in and to the Exploration Agreement.

The effect of the Exploration Agreement and the HRI Assignment was to create the following net revenue interests to the Company in Donner #1, Donner #2, and Prospect 2:

	Donner #1	Donner 2 and Prospect 2
Before payout	40.50%	36%
After payout	22.5%	27%

The main focus for the Company was a 3 to 4 well drilling and development program in The Hartburg Project. The Company successfully drilled, completed and began producing the first well in the program (the "Donner #1" well) in August 2010.

The Company completed the drilling of Prospect #1 (the "Donner #2" well), and placed the well into production during the month of August 2011.

The Company acquired the necessary permits and approvals and signed contracts for the drilling of Donner #4. The surface location of Donner #4 is approximately 500 feet southwest of the Company's Donner #1 well. The well was drilled during February 2014 and placed into production during late March 2014. However, an influx of sand into the well-bore has caused production from this well to be temporarily shut in as of December 11, 2014. The Company is evaluating options to determine if the well can be returned to production.

The Company also acquired the necessary permits, approvals and signed contracts for the drilling of the Brown #1 well. The Company paid 100% of drilling and completion costs for a 67.5% before payout net revenue interest. Drilling operations on the Brown #1 well commenced in February 2014 and were completed in March, 2014. Interpretation of wireline logs and sidewall cores recovered from the well-bore indicate the presence of moveable hydrocarbons in multiple individual reservoirs over approximately 200 feet of gross section. A 2 ½ foot interval near the base of the lowest reservoir interval in the well was perforated, flow tested and subsequently placed on production.

During the three month period ended September 30, 2014, oil production decreased to approximately 5 barrels of oil per day, while natural gas production was approximately 300 mcf per day. During the fourth quarter the Company perforated an additional pay zone in the Brown #1 well, and production has increased to approximately 500 mcf of natural gas per day. During 2014, the well produced both oil and natural gas, resulting in revenue of $301,887.

The table below shows the Company's net revenue interest share and production produced by these wells;

Well Name	Year Ended Dec. 31, 2014			Year Ended Dec. 31, 2013		
	Production (Bbls)	**Production (MCF)**	**Revenue ($)**	**Production (Bbls)**	**Production (MCF)**	**Revenue ($)**
Donner #1	3,175	-	326,754	3,493	-	358,763
Donner #2	64	25,846	124,135	124	47,909	167,034
Donner #4	305	46,953	238,640	-	-	-
Brown #1	1,315	37,027	301,887	-	-	-

Revenue for Donner #1 decreased when compared to the prior periods in the corresponding year, due to normal decline in daily oil production and a reduction in commodity prices of oil.

The significant decrease in natural gas production for Donner #2 for the year ended December 31, 2014 was due to the well not being in production for a period due to weather conditions and the onset of associated water production. The weather issues cleared and the water production issues have been resolved, hence the well returned to previous production levels near the end of March, 2014. Donner #2 started to deliver some minor condensate production associated with the gas. During the three month period ended September 30, 2014, operating costs at Donner #2 increased due to an increase in water production and the associated water disposal requirements. During the three month period ended December 31, 2014, the Company has evaluated and given their consent to abandon this reservoir section and to re-complete the well in a potentially productive zone up hole in the Donner #2 well-bore. The well was recompleted and has started to produce oil at commercial rates during the first quarter of 2015.

b) Livingston Property, Texas

By agreement dated November 1, 2009, the Company entered into an Assignment of Oil and Gas Lease and Bill of Sale for the assignment of a 30% working interest and a 22.5% net revenue interest in certain oil and gas mineral leases known as the Livingston property in Polk County, Texas. In consideration the Company paid a lump sum of $96,120 (US $90,000). The Company was responsible for their proportionate share of all future costs of the development of the property. The following table shows the production and revenue produced by this property;

Well Name	December 31, 2014		December 31, 2013	
	Production (Bbls)	Revenue ($)	Production (Bbls)	Revenue ($)
Livingston Property	403	43,012	1,116	115,547

The decrease in production and revenue for the year ended December 31, 2014 was due to the sale of the Livingston Property for US $125,000, which closed in July, 2014 but became effective on June 1, 2014.

c) Acquisition Gulf of Mexico Properties

With an effective date of December 19, 2014, The Company completed the purchase of Gulfsands Petroleum USA Inc. ("GPUSA"). GPUSA was subsequently renamed Hillcrest GOM Inc. ("HGOM"), and is now a wholly owned subsidiary of Hillcrest.

Hillcrest, through its wholly owned subsidiary HGOM, owns a portfolio of non-operated oil & gas properties in the Gulf of Mexico, within the shallow water "shelf" region offshore Louisiana. These comprise 10 leases containing 5 producing fields. Working interests in these leases range from approximately 4% to 26%. With the acquisition, the Company assumed its share of the forward Asset Retirement Obligations ("ARO") for the facilities and wells. The ARO expenditure timing ranges from near term to longer term, with the majority occurring at the end of productive field life.

The fields are relatively mature, although additional infield drilling and recompletion opportunities have been identified in the Eugene Island 32 Field. Additional exploration potential also exists in the largely undrilled deeper section in some of the leases.

Eugene Island 32

The majority of the Hillcrest oil production from the Gulf of Mexico assets is sourced from the Eugene Island 32 Field. Production is from Lower Pliocene and Upper Miocene aged conventional sandstone reservoirs contained within a large, faulted anticline structure. There are multiple proven reservoirs within the field area, occurring at vertical drilling depths of approximately 6,000 to 11,000 feet. Water depth at the Eugene Island Field is approximately 10-12 feet.

A number of infield drilling and behind pipe (recompletion or work-over) opportunities have been identified within the field, and the Company is working with the other working interest holders to optimize the development of these additional opportunities.

Other Producing Fields

Hillcrest also produces relatively small volumes of oil and gas from the Ship Shoal 271 Field, the West Cameron 310 Field, the West Cameron 498 Field and the West Delta 64 Field.

SELECTED ANNUAL & QUARTERLY INFORMATION

SELECTED ANNUAL INFORMATION

For the years ended December 31, 2014, 2013 and 2012, presented in accordance with International Financial Reporting Standards:

Audited	2014	2013	2012
Total Assets	20,495,996	4,014,585	3,553,604
Total Liabilities	18,377,583	1,169,960	170,665
Shareholders' equity	2,118,413	2,844,625	3,382,939
Revenue	1,163,004	677,435	785,622
Write down of resource properties	-	-	478,145
Foreign exchange gain/(loss)	8,095	11,899	(9,528)
Interest on Loan	170,000	67,432	-
Other income	79	117	24
Expenses	2,080,688	1,306,211	1,029,106
Net income/(loss)	(1,183,972)	(684,192)	(731,133)
Net Income (loss) per share	(0.03)	(0.02)	(0.02)

Note – The increase in total assets, liabilities, revenue and expenses for the year ended December 31, 2014, was due to the acquisition of HGOM on December 19, 2014.

SELECTED QUARTERLY INFORMATION

The table below summarized information reported for the most recent eight quarterly periods:

	Dec. 31, 2014 ($)	Sept. 30, 2014 ($)	Jun. 30, 2014 ($)	Mar. 31, 2014 ($)	Dec. 31, 2013 ($)	Sept. 30, 2013 ($)	Jun. 30, 2013 ($)	Mar 31, 2013 ($)
Total assets	20,495,996	3,736,059	3,900,169	3,812,162	4,014,585	4,235,398	3,396,572	3,531,167
Total liabilities [1]	18,377,583	1,338,504	1,251,507	1,229,180	1,169,960	1,164,428	121,000	202,956
Shareholders' equity	2,118,413	2,397,555	2,648,662	2,582,982	2,844,625	3,070,970	3,275,572	3,328,211
Revenues	**304,216**	**268,316**	**461,239**	**129,233**	**146,188**	**168,978**	**184,157**	**178,112**
Major expense items:								
Consulting fees	82,746	63,188	64,540	79,749	96,834	140,048	49,571	47,989
Professional fees [2]	80,753	19,762	29,602	9,000	57,960	4,806	30,120	34,941
Depletion [4]	352,465	120,737	186,864	36,513	51,986	81,345	89,299	98,585
Stock-Based Compensation	800	2,363	4,572	4,044	39,481	82,446	-	-
Debt issue costs [3]	42,312	31,896	33,424	31,896	-	-	-	-
Interest on Secured Loan	49,500	45,500	37,500	37,500	-	-	-	-
Gain/(loss) on disposal of assets	(42,320)	-	45,577	(87,897)	-	-	-	-
Net income (loss)	**(754,050)**	**(159,248)**	**(39,114)**	**(265,687)**	**(265,826)**	**(310,999)**	**(52,639)**	**(54,728)**
Income (loss) per share	(0.02)	(0.00)	(0.00)	(0.01)	(0.01)	(0.01)	(0.00)	(0.00)

1. Total liabilities have increased due to the liabilities from the HGOM acquisition.

2. Reduction from December 31, 2013 to March 31, 2014 due to legal fees associated with the Hartburg project.

3. Debt issue costs are amortized over the term of the loan.

4. The increase in the depletion allocation is due to the recently drilled Donner #4 and Brown #1 wells being brought into production during the three months ending June 30, 2014, and is based on preliminary management estimates for the associated remaining reserves and the acquisition of HGOM.

5. The increase in total assets, total liabilities, revenue and expense was due to the inclusion of the results from the acquisition of HGOM on December 19, 2014.

RESULTS OF OPERATIONS

For the 3 months ended December 31, 2014

The Company generated total revenue of $304,216 for the three month period ended December 31, 2014, an increase of approximately 108% from revenues of $146,188 for the three month period ended December 31, 2013. The increase in total revenue for the 3 month period ended December 31, 2014, when compared to the three month period ended December 31, 2013, was caused by the consolidation of revenue of HGOM from the acquisition date on December 19, 2014 until December 31, 2014, however this was partially offset by the reduction in production from the Livingston wells, which were sold and the shut-in period of the Donner #2 well in the Hartburg project.

Costs and Expenses

The Company incurred costs and expenses in the amount of $942,449 for the 3 months ended December 31, 2014, representing an increase of $556,996 from costs and expenses of $385,453 for 3 months ended December 31, 2013.

The significant increase in costs and expenses for the 3 months ended December 31, 2014, when compared to the 3 months ended December 31, 2013, is primarily attributable to the collective results of the following factors:

1. Operating costs relating to the production of oil and natural gas sales was $256,519 (2013: $49,137). The increase in operating costs was primarily caused by additional costs related to the commencement of production for the wells located in the Hartburg project. There were also additional operating costs related to the acquired HGOM properties.
2. Consulting fees decreased to $82,746 (2013: $96,834) for the 3 months ended December 31, 2014. These fees are related to the costs of consulting services provided by related parties and additional external specialist consultants utilized on an as needed basis.
3. Depletion and depreciation increased to $325,465 for the 3 months ended December 31, 2013, as compared to $51,986 for the corresponding period in the previous year. The increase was caused by the production from additional wells in the Hartburg project and the inclusion of depletion for HGOM.
4. Investor relations and business development costs for the 3 months ended December 31, 2014 decreased by 29% to $25,614 (2013: $36,276). The Company had reduced its investor relation marketing campaigns during the period.
5. Professional fees for the 3 months ended December 31, 2014 increased to $80,753, due to legal fees associated with the new leases in the Hartburg project, the acquisition of HGOM and general corporate matters. (2013: $57,960).
6. Stock-based compensation decreased to $800, for the 3 months ended December 31, 2014 as compared to $39,481 for the 3 months ended December 31, 2013. The Company did not issue stock options during the period (2013: 1,000,000 stock options). The Company uses the Black-Scholes valuation method to value the stock options at the time of grant.
7. Travel increased to $31,934 (2013: $9,142), primarily relating to fund raising activities and travel between Vancouver and Houston offices.
8. Wages and Benefits increased to $28,085 for the 3 months ended December 31, 2014, (2013: $nil). The increase was due to the inclusion of wages and benefits from the HGOM acquisition.

Income/(loss) before other items

The loss before other items for the 3 months ended December 31, 2014 was $638,233, compared to a loss before other items of $239,265 for the 3 months ended December 31, 2013.

Other items

The Company reported a foreign exchange gain of $628 for the 3 month to December 31, 2014, as compared to a foreign exchange gain of $10,939 for the 3 months ended December 31, 2013,

The Company reported interest paid of $49,500 for the three month period ended December 31, 2014, compared to $37,500 for the corresponding period in the prior year. During the three month period ended September 30, 2014, the Company extended the principal loan repayments of $83,333 per month by agreeing to pay an additional monthly bonus payment of $4,000.

The Company reported interest paid on an unsecured loan of $1,183 (2013: $nil) for the three month period ended December 31, 2014.

The Company paid $15,888 for the three month period ended December 31, 2014 (2013: $nil) as an overriding royalty interest on the secured loan facility.

The Company reported a loss on disposal of the Montana – Bakken Woodrow project of $87,897; a gain on disposal of the Montana – Muddy Creek project of $84,547, resulting in a total loss on disposal of $3,350 for the Montana properties. In addition, the Company reported a loss on disposal of the Livingston property of $38,970.

Net Loss and Comprehensive loss for the period

Comprehensive loss for the 3 months ended December 31, 2014 was $754,050, compared to a comprehensive loss of $265,826 for the 3 months ended December 31, 2013. The increase in loss for the 3 months ended December 31, 2014 was attributable to the items indicted above.

For the year ended December 31, 2014

The Company generated total revenue of $1,163,004 for the year ended December 31, 2014, an increase of approximately 73% from revenues of $677,435 for the year ended December 31, 2013. The increase in total revenue for the year ended December 31, 2014, when compared to the year ended December 31, 2013, was due to the additional production from the Donner #4 and Brown #1 wells in the Hartburg project and the inclusion of revenue from HGOM. These revenue increases were partially offset by a reduction in revenue from the sale of the Livingston Property.

Costs and Expenses

The Company incurred costs and expenses in the amount of $2,080,688 for the year ended December 31, 2014, representing approximately a 57% increase from costs and expenses of $1,306,211 for year ended December 31, 2013.

The increase in costs and expenses for the year ended December 31, 2014, when compared to the year ended December 31, 2013, is primarily attributable to the following factors:

1. Operating costs relating to the production of oil and natural gas sales was $495,632 (2013: $147,405). The increase in operating costs was primarily caused by the additional costs for the Livingston wells as some wells incurred work-over costs to maintain production levels, however this was partially offset by the disposal of these wells during 2014. There were also additional costs related to Donner #2 in the Hartburg project due to salt water disposal and costs associated with bringing the two new wells into production during the period. There were also additional operating costs related to the acquired HGOM properties.
2. Consulting fees decreased by 10% to $290,223 (2013: $334,442). The decrease was due to a reduction of amounts paid to a director of the Company and other consultants that the Company contracted to further its corporate development initiatives
3. Debt issue costs for the year ended December 31, 2014 were $139,528 (2013: $63,792). These costs are caused by the issue of the secured loan and will be amortized over the term of the loan. At December 31, 2014, the remaining debt issue costs to be amortized are $63,792.
4. Depletion and depreciation increased to $696,579 (2013: $321,215). The significant increase in depletion was caused by costs relating to Donner #4 and Brown #1 being amortized based on their respective production, and the inclusion of depletion costs related to the recently acquired HGOM assets.
5. Investor relations and business development costs increased to $121,370 (2013: $100,999). The increase of 20% was caused by the Company embarking on an investor marketing and fund raising campaign.
6. Professional fees were $139,119 (2013: $127,821). Professional fees increased due to legal fees related to the acquisition of new leases for the Hartburg project, the acquisition of HGOM and for general corporate matters.
7. Stock-based compensation was $11,779 (2013: $121,927) for the year ended December 31, 2014. The Company did not grant any stock options during the current year, whereas 2,750,000 options were granted in the prior year. The Company utilizes a Black-Scholes option pricing model to value stock options on the grant date.
8. Travel increased to $65,896 (2013: $34,630) due to increased fund raising and business development activities and travel between the Vancouver and Houston offices.
9. Wages and Benefits increased to $28,085 for the 3 months ended December 31, 2014, (2013: $nil). The increase was due to the inclusion of wages and benefits from the HGOM acquisition.

Income (loss) before other items

The loss before other items for the year ended December 31, 2014 was $917,684, compared to a loss before other items of $628,776 for the year ended December 31, 2013.

Other items

The Company reported other income generated from a foreign exchange gain of $8,095 for the year ended December 31, 2014, as compared to a foreign exchange gain of $11,899 for the year ended December 31, 2013. The US dollar has strengthened substantially against the Canadian dollar during 2014, and all the Company's oil and gas production is received in United States dollars.

The Company reported other income arising from interest earned of $79 (2013: $117).

The Company paid $170,000 as interest on its senior secured loan facility for the year ended December 31, 2014 (2013: $67,432). During the year the Company extended the principal loan repayments of $83,333 per month by agreeing to pay an additional monthly bonus payment of $4,000.

The Company reported interest paid on an unsecured loan of $1,498 (2013: $nil) for the year ended December 31, 2014.

The Company paid $44,875 (2013: $nil) for the year ended December 31, 2014 as an overriding royalty interest related to the secured loan facility.

The Company paid $15,769 in acquisition costs for the year ended December 31, 2014 (2013: $nil). These costs related to the acquisition of HGOM.

For the year ended December 31, 2014, the Company reported a loss on disposal of the Montana – Bakken Woodrow project of $87,897; a gain on disposal of the Montana – Muddy Creek project of $84,547, resulting in a total loss on disposal of $3,350 (2013: $nil), for the Montana properties. In addition, a $38,970 loss was realized on disposal of the Livingston property for the year ended December 31, 2014 (2013: $nil).

Net Loss and Comprehensive loss for the period

Comprehensive loss for the year ended December 31, 2014 was $1,218,099, compared to a comprehensive loss of $684,192 for the year ended December 31, 2013. The increase in loss for the year ended December 31, 2014 was attributable to the items indicated above, in particular depletion charges, interest, overriding royalty payments and the loss on disposal of oil and gas properties.

LIQUIDITY AND CAPITAL RESOURCES

The Company had a working capital deficiency of $1,277,561 as at December 31, 2014, compared to $260,873 as at December 31, 2013. The increase in working capital deficiency was caused by the issuance of a senior secured loan facility of $1,000,000, however, this was reduced by the expenses incurred in arranging the facility; the inclusion of the current portion of the decommissioning liability and the increase in accounts payable and accrued liabilities.

On September 9, 2014, the Company amended the senior secured loan terms such that if the principal payments were not paid on their due dates, then the Company would pay the contracted rate of 15% interest plus an additional $4,000 until the loan payments are caught up. The Over Riding Royalty Interest will be increased from 8% to 10% of the Net Revenue Interest received by the Company on its Brown #1 and Donner #4 wells. The Parties agreed, as a minimum the revenue received from Brown #1 and Donner #4 less any Joint Interest Billings on these wells each month until the Company has paid all past outstanding principal payments. These latter payments will be considered as part payment of the principal amount due

The revenue currently generated from natural gas and oil sales does not exceed the Company's operating expenses. As a result, management anticipates that the current cash on hand may not be sufficient to fund continued operations at the current level for the next twelve months. The Company will also require additional funds to complete well activities on existing wells and to drill additional wells on the Hartburg and HGOM properties and to acquire and develop additional oil and natural gas assets to implement the Company's overall growth strategy. Management has successfully utilized both debt and equity financing in the past, but there is no assurance that such funding will be available in the future or if it is that it will be on terms that are acceptable. If The Company is unable to obtain additional financing, it will experience liquidity problems and management expects that it will need to curtail operations, liquidate assets, seek additional capital on less favorable terms and/or pursue other remedial measures. Any additional equity financing may involve substantial dilution.

Cash flows provided by Operating Activities

Operating activities used $128,290 in cash for the year ended December 31, 2014, compared to $123,270 in cash used in operating activities for the year ended December 31, 2013. The Company's increase in cash used in operations was caused by the inclusion of operations resulting from the HGOM acquisition which was partially offset in an increase in revenues from new wells becoming productive in the Hartburg project.
Cash Used in Investing Activities

Cash flows used in investing activities for the year ended December 31, 2014 was $(504,577), compared to $60,078 cash flows from investing activities for the year ended December 31, 2013. The Company finalized its sale of 50% of its holding in Muddy Creek for US$400,000 and sold the Livingston property for $125,000 US. However this was offset by costs related to the drilling of Donner #4, Brown #1 and acquisition of further leases in the Hartburg project.

Cash flows from Financing Activities

The Company received $6,000 for the year ended December 31, 2014 related to the exercise of 100,000 stock options at an exercise price of $0.06 per share. (2013: $nil). The Company also received $50,000 from an unsecured loan incurring an interest of 10% per annum. The Company received aggregate proceeds of $485,250 from the issuance of common share pursuant to a private placement of 10,625,000 common shares at a price per share of $0.05.

Off-Balance Sheet Arrangements

The Company did not have any off-balance sheet debt nor did it have any transactions, arrangements, obligations (including contingent obligations) or other relationships with any unconsolidated entities or other persons that may have material current or future effect on financial conditions, changes in the financial conditions, results of operations, liquidity, capital expenditures, capital resources, or significant components of revenue or expenses.

OUTSTANDING SHARE DATA

The total number of common shares outstanding as of the Report Date was 50,295,655.

SHARE PURCHASE WARRANTS

The total number of share purchase warrants outstanding as of April 29, 2015 was 6,165,611 at a weighted average exercise price of $0.09 per share, exercisable until February 28, 2016 and December 30, 2016.

The total number of Agent's warrants outstanding as of April 29, 2015 was 1,360,000 at a weighted average exercise price of $0.10 per share, exercisable until July 18, 2015 and December 30, 2015.

STOCK OPTIONS

The total number of stock options outstanding as of April 29, 2015 was 2,950,000 (2013: 4,600,000) at a weighted average exercise price of $0.11 per share (2013: $0.12).

COMMITMENTS

The Company entered into a rental agreement on June 3, 2013, with a term of 50 months, terminating on July 31, 2017. The base rent payable under the lease is as follows;

Period	**Annual Base Rent (USD) $**
January 1, 2015 to July 31, 2015	US $ 55,545
August 1, 2015 to July 31, 2016	98,105
August 1, 2016 to July 31, 2017	101,031
	US $ 386,812

In addition to the above base rent, the Company's share of the operating costs for calendar year 2015 is US $5,306 per month.

RELATED PARTY TRANSACTIONS

Related party transactions are with directors, officers or corporations controlled by a director or officer of the Company.

The following summarizes the Company's related party transactions during the year ended December 31, 2014 and 2013:

	2014 ($)	2013 ($)
Consulting fees paid or accrued to the Chief Executive Officer of the Company	90,000	90,000
Consulting and accounting fees paid to companies controlled by the Chief Financial Officer of the Company	78,000	73,500
Consulting fees to Directors	72,056	54,085
Salaries paid to an Officer	11,618	-

a) As at December 31, 2014, the Company owed $10,618 (2013 - $10,131) to the Chief Executive Officer which is included in accounts payable and accrued liabilities.
b) Stock-based compensation of $nil was recognised during the year ended December 31, 2014 (2013 - $68,117), related to stock options granted to directors and officers.
c) These transactions are in the normal course of operations and are measured at the exchange amount of consideration established and agreed to by the related parties.

ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

Significant accounting policies used by Hillcrest are disclosed in note 3 to the December 31, 2014 audited annual consolidated financial statements. Preparing financial statements in accordance with IFRS requires management to make certain judgments and estimates. Changes to these judgments and estimates could have a material effect on the Company's financial statements and financial position. There were no changes to Hillcrest's critical accounting estimates during the year ended December 31, 2014.

NEW ACCOUNTING STANDARDS AND PRONOUNCEMENTS

The following describes new accounting pronouncements that been issued but are not yet effective:

Share-based payment (IFRS 2)
IFRS 2 is amended to clarify the definition of vesting conditions. This accounting policy applies to share-based payment transactions for which the grant date is on or after July 1, 2014.

Business combinations (IFRS 3)
IFRS 3 is amended to provide clarification related to (i) contingent consideration in a business combination and (ii) scope exception for joint arrangements. These amendments are effective for fiscal years beginning on or after July 1, 2014.

Operating segments (IFRS 8)
IFRS 8 is amended to require (i) disclosure of judgments made by management in aggregating segments, and (ii) a reconciliation of segment assets to the entity's assets when segment assets are reported. These amendments are effective for fiscal years beginning on or after July 1, 2014.

Financial instruments (IFRS 9)
IFRS 9 replaces IAS 39 "Financial Instruments: Recognition and Measurement", which eliminates the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classifications: amortized cost and fair value. In November 2013, the IASB amended IFRS 9 to include the new general hedge accounting model which remains optional, allows more opportunities to apply hedge accounting, and will be effective on January 1, 2018 and applied retroactively to each period presented.

Property, plant and equipment (IFRS 16) and intangible assets (IFRS 38)
IFRS 16 and 38 are amended to classify how gross carrying amount and accumulated depreciation are treated where an entity uses the revaluation model. These amendments are effective for fiscal years beginning on or after July 1, 2014.

Related party transactions (IFRS 24)
IFRS 24 is amended to (i) revise definition of "related party" to include an entity that provides key management personnel services to the reporting entity or its parent, and (ii) clarify related party disclosure requirements. These amendments are effective for fiscal years beginning on or after July 1, 2014.

Management anticipates that the above standards will be adopted in the Company's financial statements for the period beginning January 1, 2015 or later, and currently evaluating the impact of the adoption of these standards.

CAPITAL MANAGEMENT

The Company manages its capital structure and makes adjustments to it, based on the funds available to the Company, in order to support the acquisition, exploration and development of resource properties. The Board of Directors does not establish quantitative return on capital criteria for management, but rather relies on the expertise of the Company's management to sustain future development of the business.

The Company is dependent on external financing to fund its activities. In order to carry out planned exploration and development and pay for administrative costs, the Company will spend its existing working capital and raise additional funds as needed. The Company will continue to assess new properties and seek to acquire an interest in additional properties if it feels there is sufficient geologic or economic potential and if it has adequate available or committed financial resources to complete such acquisitions.

Management reviews its capital management approach on an ongoing basis and believes that this approach, given the size of the Company, is reasonable.

There were no changes in the Company's approach to capital management during the year ended December 31, 2014.

DISCLOSURE CONTROLS AND PROCEDURES

Management has assessed the effectiveness of the Company's disclosure controls and procedures used for the financial statements and MD&A as at December 31, 2014. Management has concluded that the disclosure controls are effective in ensuring that all material information required to be filed has been made known to them in a timely manner. The required information was effectively recorded, processed, summarized and reported within the time period necessary to prepare the annual filings. The disclosure controls and procedures are effective in ensuring that information required to be disclosed pursuant to applicable securities laws are accumulated and communicated to management as appropriate to allow timely decisions regarding required disclosure. Additional disclosures pertaining to the Company's material change reports, press releases and other information are available on the SEDAR website at **www.sedar.com**

HEAD OFFICE

3050 Post Oak Blvd – Suite 1700
Houston, Texas
United States 77056

REGIONAL OFFICE

304 – 750 West Pender Street

Vancouver, BC V6C 1G8

Tel: (604) 488 - 1514

LISTINGS

TSX Venture Exchange: **HRH**

AUDITOR

Lancaster & David CA
510 - 701 West Georgia Street,
Vancouver, BC V7Y 1C6

OFFICERS & DIRECTORS

Donald Currie,
CEO and Director

Kulwant Sandher, CA
CFO

Thomas Milne
Director

Michael Krzus
Director

Dr. David Stone
Director

TRANSFER AGENT

Computershare Canada
510 Burrard Street
Vancouver, BC V6C 3A8

LEGAL COUNSEL

McMillan LLP
Royal Centre 1055 West Georgia Street
Vancouver, BC V6E 4N7