Mahalo Energy Ltd.

Annual Information Form

Year Ended December 31, 2008

March 31, 2009

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DATE OF INFORMATION

Unless otherwise specified, information in this annual information form ("**AIF**") is as at the end of the Company's most recently completed financial year, December 31, 2008.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this AIF and in certain documents incorporated by reference may constitute "forward-looking statements". The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward-looking statements. These forward-looking statements are based on current expectations and involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from any future results. The Company believes that the expectations reflected in these forward-looking statements are based on reasonable assumptions but no assurance can be given that these expectations will prove to be correct. The forward-looking statements included in this document should not be unduly relied upon.

In particular, this document and the documents incorporated by reference contain forward-looking statements pertaining to oil and natural gas production levels and the sources of their growth; capital expenditure programs; the estimated quantity of oil and natural gas reserves and recovery rates; projections of commodity prices and costs; supply and demand for oil and natural gas; planned construction and expansion of facilities; drilling plans; reserve life; plans for and results of exploration and development activities; expectations regarding the Company's ability to raise capital and to continually add to reserves through acquisitions, exploration and development; and treatment under governmental regulatory regimes and tax laws.

The Company's actual results could differ materially from those anticipated in these forward-looking statements as a result of risk factors including general economic, market and business conditions; volatility in market prices for oil and natural gas; risks inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; incorrect assessments of the value of acquisitions; geological, technical, drilling and processing problems; actions by governmental authorities, including increases in taxes; the availability of capital on acceptable terms; fluctuations in foreign exchange or interest rates and stock market volatility; and other factors discussed under "Risk Factors" in this AIF. These factors should not be construed as exhaustive. The forward-looking statements contained herein are as of March 31, 2009 and are subject to change after this date. The Company undertakes no obligation to update or revise any forward-looking statements should circumstances or Management's estimates or opinions change, except as required by law.

SPECIAL NOTE REGARDING NON-GAAP FINANCIAL MEASURES

The Company uses and makes reference to "funds from operations", "funds from operations per share", "operating netback" and "net debt". These terms do not have any standardized meaning, are not defined under Canadian Generally Accepted Accounting Principles ("**GAAP**") and are therefore referred to as non-GAAP financial measures. The non-GAAP measures, as calculated and used by the Company, may not be comparable to similar titled measures reported by other companies.

Management considers these non-GAAP measures as useful supplemental measures to analyze operations, compare performance between periods and provide shareholders and potential investors with additional information. These non-GAAP measures are also used by research analysts to value and compare oil and gas exploration and production companies, and are frequently included in published research when providing investment recommendations.

Funds from operations and funds from operations per share should not be considered as an alternative to, or more meaningful than net earnings, cash provided by operating, financing and investing activities or other measures of financial performance or liquidity calculated in accordance with Canadian GAAP. Funds from operations represent cash from operating activities before change in related non-cash working capital. Funds from operations per share are calculated using the weighted average shares outstanding, consistent with the calculation of net income per share. These measures are used by Mahalo to assess its operating results and its ability to generate funds to finance future operations and to service debt.

Operating netback should not be considered an alternative to, or more meaningful than, net earnings or other measures of financial performance or liquidity as determined in accordance with Canadian GAAP. Operating netback presents a measure of net oil and gas revenue relative to realized commodity prices by deducting royalties and operating and transportation costs from oil and gas sales revenues. This non-GAAP measure is used by the Company to assess comparability of petroleum sales and directly related costs on a per unit basis between periods.

Net debt, as calculated by the Company, represents long-term debt less working capital (excluding unrealized gain or loss on financial instruments) and is used by the Company to assess financial strength.

USE OF BARREL OF OIL EQUIVALENTS AND OTHER ADVISORIES

In this document, a barrel of oil equivalent ("**boe**") conversion ratio of 6 Mcf to 1 bbl has been used. The oil and gas industry commonly expresses production, sales and reserves on a barrel of oil equivalent ("boe") basis. The boe measure is used by the Company to aggregate oil and gas volumes. The measure is also considered to be useful for comparisons with other industry participants. The boe conversion ratio of 6 Mcf to 1 bbl is based on an approximate energy equivalency of these commodities at the burner tip and does not represent a value equivalency at the well head. This conversion may therefore be misleading, particularly if used in isolation.

Unless otherwise noted, the Company's production volumes disclosed herein are based on the Company's working interest production before deduction of royalties paid to others including royalty volumes received. In addition, production volumes are quoted in terms of "raw" gas while sales volumes and estimated remaining recoverable reserves are expressed in terms of "sales" gas. Raw gas reflects the quantity of field production at the wellhead. During gathering and processing, a portion of the raw gas may be used to fuel the processing facility and to run certain instrumentation devices. In certain cases, but not usually in the case of CBM which is primarily methane, the gas may be accompanied by hydrocarbon liquids which when separated, further reduces the amount of gas available for sale. The aggregate impact of these factors is usually referred to as "shrinkage".

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

In this Annual Information Form, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated. References to "US$" are to United States dollars.

GLOSSARY OF TERMS

In this Annual Information Form, unless the context otherwise requires, the following words, terms and abbreviations shall have the meanings set forth below:

"**ABCA**" means the *Business Corporations Act* (Alberta), R.S.A. 2000, c. B-9, as amended together with all regulations promulgated thereunder;

"**AENV**" means Alberta Environment;

"**AEPEA**" means the *Alberta Environmental Protection and Enhancement Act*;

"**AEUB**" means the Alberta Energy and Utilities Board;

"**CBM**" means coalbed methane;

"**Cdn$**" means Canadian dollars;

"**CICA**" means the Canadian Institute of Chartered Accountants;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy and Petroleum;

"**Common Shares**" means common shares in the share capital of the Company;

"**development well**" means a well drilled into a zone that is known to be productive and expected to produce crude oil or natural gas in the future;

"**dry well**" means a well drilled that is not capable of producing commercial quantities of crude oil or natural gas to justify completion. A dry well will be plugged back, abandoned and reclaimed;

"**exploratory well**" means a well drilled into an unproven territory with the intention to discover commercial quantities of crude oil or natural gas;

"**economic life**" means, with respect to an oil and natural gas property, the time remaining before production of petroleum substances from the property is forecast to be uneconomic under forecast cost and price assumptions;

"**field production volumes**" means field gathered raw gas production volumes prior to any processing or shrinkage and prior to sales;

"**GAAP**" means Canadian generally accepted accounting principles;

"**Gross**" or "**gross**" means:

(a) in relation to the Company's interest in production or reserves, its working interest (operating and non-operating) share before deduction of royalties, and without including any royalty interests of the Company;

(b) in relation to the Company's interest in wells, the total number of wells in which the Company has an interest; and

(c) in relation to the Company's interest in properties, the total area of properties in which the Company has an interest;

"**joint venture**" means an economic activity resulting from a contractual arrangement whereby two or more venturers jointly control the economic activity;

"**Net**" **or** "**net**" means:

(a) in relation to the Company's interest in production or reserves, its working interest (operating and non-operating) share after deduction of royalty obligations, plus any royalty interests of the Company in production or reserves;

(b) in relation to the Company's interest in wells, the total number of wells obtained by aggregating the Company's working interest in each of its gross wells; and

(c) in relation to the Company's interest in properties, the total area of properties in which the Company has an interest multiplied by the working interest owned by the Company;

"**Mahalo Energy Ltd.**", "**Mahalo**" or "**Company**" means Mahalo Energy Ltd. and includes, where applicable, reference to subsidiaries of Mahalo Energy Ltd.;

"**Netherland Sewell**" means Netherland, Sewell & Associates, Inc., independent engineers and authors of the NSAI Report;

"**NSAI Report**" means the report of Netherland Sewell dated March 20, 2009 evaluating the coalbed methane, shale gas, natural gas, crude oil and natural gas liquids reserves of the Company effective December 31, 2008;

"**NI 51-101**" means National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities adopted by the Canadian Securities Administrators;

"**NI 51-102**" means National Instrument 51-102 - Continuous Disclosure Obligations adopted by the Canadian Securities Administrators;

"**productive well**" means a well that is not dry;

"**sales volumes**" means actual metered sales volumes after all required processing and associated shrinkage;

"**SEDAR**" means the System for Electronic Analysis and Retrieval; a central repository where documents required to be filed by Canadian public companies can be retrieved by the relevant regulatory agencies and the public;

"**Tax Act**" means the *Income Tax Act* (Canada) R.S.C. 1985, c.1 (5th Supp.), as amended;

"**TSX**" means the Toronto Stock Exchange;

"**undeveloped land**" means land on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas;

"**US$**" means United States dollars;

"**United States**" or "**U.S.**" means the United States of America;

"**Vectra**" means Vectra CBM, LLC, a corporation organized under the laws of Colorado; and

"working interest" means the interest held by the Company in a crude oil or natural gas property, which interest normally bears its proportionate share of costs of exploration, development and operating costs as well as any royalties or other production burdens.

Certain other terms used in this Annual Information Form but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	Barrel
bbls	Barrels
bbls/d	Barrels per day
Mbbls	Thousand barrels
MMbbls	Million barrels
Bopd	Barrels of oil per day
NGLs	Natural gas liquids
STB	Stock tank barrel

Natural Gas

Mcf	Thousand cubic feet
MMcf	Million cubic feet
Bcf	Billion cubic feet
Mcf/d	Thousand cubic feet per day
MMcf/d	Million cubic feet per day
MMscf	Million standard cubic feet
gj	Gigajoule
gjs/d	Gigajoules per day
Btu	British thermal unit

Other

AECO	The natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	An indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil
ARTC	Alberta Royalty Tax Credit
BOE or boe	Barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
m^3	Cubic metres
MBOE	Thousand barrels of oil equivalent
MSTBOE	Thousand stock tank barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
PSI	Pounds per square inch

CONVERSION FACTORS

The following table sets forth certain standard conversions between the Standard Imperial units of measurement and the International System of Units (or metric units) of measurement.

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	Mmbtu	0.950

MAHALO ENERGY LTD.

Mahalo was incorporated under the ABCA on April 21, 2004. Mahalo's head office is located at Suite 540, 734 - 7th Avenue S.W., Calgary, Alberta, T2P 3P8 and its registered office is located at Suite 1400, 350 - 7th Avenue S.W., Calgary, Alberta, T2P 3N9. On May 31, 2006, Mahalo completed an arrangement with Alberta-based Peregrine Energy Ltd. ("**Peregrine**"). Mahalo and Peregrine subsequently amalgamated on January 1, 2007 and continued under the name "Mahalo Energy Ltd." As of January 1, 2009, Mahalo had one wholly-owned subsidiary, Mahalo Energy (USA) Inc., a company incorporated under the laws of Delaware.

MAHALO'S BUSINESS

Mahalo is an Alberta-based junior, unconventional natural gas producer, focused principally on the acquisition, exploration, development and production of coalbed methane ("**CBM**") and shale gas prospects in the United States. In 2008, the Company made the decision to dispose of all of its Canadian resource assets and operations, which decision resulted in the sale of the majority of the Company's Canadian operations.

Mahalo's business plan is focused on exploration, development, and exploitation drilling and production operations complemented by property and production acquisitions exhibiting synergy in lands, facilities, production and operating efficiencies.

Mahalo has successfully acquired a large acreage position through its exploration, land, engineering and operations groups who employ a synergistic team approach in identifying and sourcing quality acreage that has CBM and natural gas growth potential in the United States.

Mahalo attempts to deliver reserves and new production through the exploration and development drill bit in order to expand production and cash flow. In this regard, Mahalo does not preclude itself from acquiring producing assets or corporate bodies; provided, these acquisitions demonstrate near term value accretion on a per share basis, new drilling or re-completion opportunities supported by cost effective infrastructure (both operated and third party) and topography that has the potential to deliver reasonable cycle time.

The Company is currently focusing its United States CBM exploration and development efforts on Hartshorne and McAlester coal formations in the State of Oklahoma. The Company's shale gas exploration and development efforts are currently restricted to the State of Oklahoma in the United States and are currently focused on Caney and Woodford shales.

The Company's United States CBM and shale gas operations are being conducted by Mahalo or its joint venture partners, including Vectra CBM, LLC, a private U.S. company, Williams Production Mid-Continent Company, a subsidiary of The Williams Companies, Inc., a public U.S. company and certain other producing companies pursuant to operating agreements.

Coalbed Methane Gas

Natural gas from coal, commonly referred to as coalbed methane, is methane gas which occurs in coal seams. Until the early 1980's, the natural gas industry considered CBM to be a coal mining industry problem. CBM was a nuisance and hazard to coal mining as opposed to a potential source of low-cost gas. Even though coal is the source rock for conventional reservoirs, coal seams were not considered as completion targets because it was considered improbable that a thin, shallow horizon could hold economic quantities of gas.

With the growing demand for energy, producers began looking for sources of natural gas from more difficult, tighter sands. In the 1990's, companies began looking to exploit CBM from coalbeds. With an understanding of the storage and production mechanism, and modifications to conventional oil and gas technology, CBM became recognized as an important source of economic gas. CBM gas is now produced economically by drilling conventional style gas wells but employing special completion techniques which are specific to this type of reservoir. Coalbed natural gas is virtually identical to the sweet gas produced from conventional sandstone reservoirs.

Coal is unusual as a reservoir since it is both the source rock and the reservoir for the gas. Coal seams contain small, regularly spaced, naturally occurring fractures referred to as cleats. In a CBM reservoir, gas molecules are attached to the coal matrix in an adsorbed state and water maintains the reservoir pressure that holds the gas in the coals. Typically, water must be produced from coal seams to reduce reservoir pressure to release the gas. As pressure in the coal seam depletes, gas molecules detach from the coal surface and diffuse through the matrix until they reach a natural fracture or cleat system, forcing gas through the fractures to the well bore.

Ultimate gas recovery from CBM wells is a function of complex relationships between permeability, thickness, coalbed gas content and well spacing, but the production rates for the first portion of the well's economic life are almost solely dependent on the coal seam permeability and gas content. For a successful coal project, producers must accurately characterize reservoir properties and apply the available technology to optimize production.

Shale Gas

With the advances in oil and gas technology, expectations of higher gas prices reflective of increased demand coupled with depleting conventional gas reservoirs, certain industry producers have become focused on exploration for and production of gas from shale, which generally has lower permeability than coal.

Because of its very low permeability, shale often forms geologic seals retaining oil and gas within conventional oil and gas producing reservoirs. In a number of geologic basins, however, layers of shale, sometimes hundreds of feet thick, can be a source as well as a reservoir for natural gas. Shale is typically rich in organic carbon. Gas forms when the organic matter left in the rock breaks down under rising temperature and pressure. The amount of heat and pressure determine the ultimate amount of hydrocarbons and whether or not such hydrocarbons are in liquid form or gas.

Most thermally mature shale contains only dry gas. Less mature shale typically contains wet gas or even oil. Although shale gas is more difficult to extract, it is usually clean and dry. Due to thickness and high organic content, shale can hold large quantities of natural gas. As a result of low permeability shale releases gas slowly thus producing at relatively predictable rates over long periods of time. Modern technologies, including hydraulic fracturing and horizontal drilling, are playing a significant role in enhancing recovery of gas from shale.

GENERAL DEVELOPMENT OF THE BUSINESS

Year ended December 31, 2006

The Company engaged in an active exploration and development program in 2006. During first quarter 2006, the Company initiated commercial CBM production in Canada and purchased an additional working interest in land and producing assets in the Poteau field in Oklahoma with Common Shares and cash.

In May 2006, the Company completed a plan of arrangement (the "**Arrangement**") with Peregrine Energy Ltd. ("**Peregrine**"), wherein the Company issued 15,153,630 Common Shares to former shareholders of Peregrine upon completion of the Arrangement on the basis of 0.48 of a Common Share for each issued an outstanding Common Share of Peregrine. Under the terms of the Arrangement, the Company paid approximately $93 million in total consideration (consisting of 15,153,630 Common Shares and the assumption of approximately $12.6 million in debt) to purchase all of the issued and outstanding shares of Peregrine. Under the terms of the Arrangement, all outstanding convertible securities of Peregrine were exchanged for comparable convertible securities of Mahalo on the same exchange ratio.

The effect of the Arrangement was that the Company acquired interests in additional undeveloped lands, seismic and approximately 1,000 boe per day of oil and natural gas production in western Canada. In connection with the Arrangement, the Company was able to secure the personnel of Peregrine and restructured its board of directors to include certain former directors of Peregrine. The acquisition added strength and depth to Mahalo's management team, helping the Company to further explore its CBM and shale drilling prospects. This is consistent with the Company's strategy of focusing on developing CBM and shale gas opportunities in North America.

During third quarter 2006, the Company's revolving bank credit facility with the Union Bank was re-negotiated to effectively consolidate Mahalo and Peregrine's debt facilities into a Cdn $75 million credit facility. At December 31, 2006, the facility had an approved borrowing base of Cdn $53 million.

The Company saw solid drilling success in its CBM development program at Lakeview, Oklahoma in 2006. During this period, natural gas prices continued to remain volatile and at levels significantly lower than that seen in 2005. Based on its United States drilling results, uncertainty caused by softer gas prices and more favourable operating economics, the Company, in fourth quarter 2006, announced its intention to direct a majority of near and medium term capital toward unconventional resource activity in the United States.

In December 2006, the Company had average crude oil and natural gas sales of approximately 2,800 boe per day net to Mahalo.

Year ended December 31, 2007

The Company's Hartshorne drilling success continued in 2007, including the introduction of multi-lateral horizontal wells to more rapidly and efficiently desorb and dewater the coal. Mahalo also drilled some shale wells in the United States as well as Mannville CBM and conventional wells in Canada. During this period, the Company also moved into an active operator role on a portion of its drilling program, bringing a better balance to its overall resource management, while continuing to benefit from a close association with joint venture partners and other operators.

In Canada, Mahalo focused its 2007 CBM efforts on one property, namely Corbett Creek, to gain a better understanding of the Mannville coal. The Company remained confident that horizontal drilling, which had been the key to its United States CBM success, would continue to be central to economically unlocking the Mannville. The conversion of single lateral horizontal wells to multi-laterals with up to three legs proved to be of benefit, noticeably reducing dewatering time and improving well production capability.

In 2007, Mahalo continued to work diligently along side other United States exploration and development companies to further develop, test and prove various concepts related to successful exploitation of the Woodford and Caney shale. In addition to conducting 3D seismic, the Company also drilled both vertical and horizontal shale wells in 2007. The Company continued to rationalize its asset base in 2007, disposing of certain higher cost Canadian conventional resource properties, along with the related asset retirement obligations, for approximately $18 million. Mahalo also sold approximately 6,700 net acres of oil, gas and mineral deep rights below the base of the Hartshorne formation in its Island, Oklahoma field to a private United States oil and gas company for US $8.4 million (US $1,250 per net acre). The Company realized proceeds of US $6.6 million from the sale, after deductions and settlement of US $1.8 million of outstanding farm-in obligations. In addition, Mahalo retained an overriding royalty.

In late 2007, Mahalo completed the sale of its 100 per cent working interest in a natural gas processing facility and gathering lines at Corbett Creek, Alberta to an Alberta-based, midstream company for Cdn $4.7 million. Mahalo also entered into a natural gas gathering and processing arrangement with the purchaser under which all of Mahalo's existing and future natural gas production from the Corbett Creek area is dedicated to the Corbett Creek facility. Proceeds from the asset dispositions were re-deployed principally towards unconventional resource development, debt reduction and working capital.

The Company's fourth quarter 2007 sales volumes averaged 3,542 boe per day, despite the disposition earlier in 2007 of certain higher cost, non-core conventional oil and gas properties producing approximately 500 boe per day. In comparison, fourth quarter 2006 sales volumes averaged 2,972 boe per day. In addition to successful exploration and development in 2007, sales volumes also benefited from expansion of the Kayla West pipeline system allowing for tie-in of several previously constrained Hartshorne CBM wells.

Although 2007 was a financially challenging year with the average realized gas price slipping below the level realized in the prior year, the Company ended 2007 with a net debt level of approximately $53 million, substantially unchanged from a year earlier. In March 2007, the approved borrowing base under Mahalo's credit facility was increased to Cdn $60 million, based on successful United States CBM drilling results.

Year ended December 31, 2008

During the first half of 2008, North American oil and gas prices were reaching for new highs, fuelling renewed optimism within the oil and gas industry. In May 2008, Mahalo decided to monetize its Canadian oil and gas property interests and apply proceeds to reduce debt so the Company could better focus on its United States Hartshorne CBM and Woodford and Caney Shale assets and opportunities. In conjunction with this decision, the Company added a number of key individuals to lead and further strengthen the team in its Tulsa, Oklahoma office.

On June 30, 2008, the Company closed a new, four year US $105 million credit facility with Ableco Finance LLC, ("**Abelco**") and Wells Fargo Foothill, LLC (together, the "**Lenders**"), replacing a $75 million facility which was due to expire in early 2009. The new facility included a US $65 million revolving credit facility (with an initial borrowing base set at US $50 million), a US $25 million term facility (fully funded at closing), and a US $15 million delay draw term facility (for future acquisitions and capital expenditures, subject to the satisfaction of certain pre-conditions).

By early July, the price for West Texas Intermediate (WTI) crude oil had reached US $147 per barrel while natural gas prices (Henry Hub) were over US $13 per Mcf. With the significant improvement in commodity prices, the Company elected to accelerate its 2008 US CBM drilling program and the re-entering of certain existing wells to add horizontal laterals.

The optimism driven by the significant and rapid improvement in commodity prices was, unfortunately, short-lived. World financial markets and commodity prices weakened significantly in the second half of 2008. By the end of the third quarter, WTI had declined to US $100 per barrel and Henry Hub natural gas had declined to US $7 per Mcf. The rapid decline in commodity prices caused many companies, including Mahalo, to re-assess their capital spending and activity levels. By year-end 2008, the worldwide financial crisis had gotten significantly worse and oil and gas prices were down to approximately US $45 per barrel for WTI and less than US $6 per Mcf for Henry Hub gas, respectively. Oil and gas prices continued to retreat to even lower levels and reflect increased volatility and economic uncertainty following the year-end.

Although the Company's 2008 CBM drilling program was successful, production from certain existing wells did not hold up as expected. Consequently, production levels that were anticipated and committed to during earlier credit facility negotiations were not achieved. The lower than anticipated production also affected cash flows. As a result, the Company breached certain of its September 30, 2008 covenants under its credit agreement; the breaches constituted "Events of Default" under its credit agreement.

Effective November 28, 2008, the Company reached an agreement with its Lenders to amend the credit facility agreement (the "**Amendment**") resulting in a waiver of the "Events of Default". The Amendment included new production and hedging requirements and revised current ratio covenants for the period October 31, 2008 through December 31, 2009. The Company also agreed to engage an advisor to assist with financial and accounting matters.

Under the Amendment, an additional US $5.0 million revolving loan advance was made to the Company to meet ongoing cash requirements. The advance was short term and repayable on March 31, 2009. The Amendment also requires the Company to pay a loan fee (the "**Loan Fee**") of between US$5 million and US$10 million, dependent upon achieving certain specific restructuring and/or refinancing initiatives by March 31, 2009. Subsequent to executing the Amendment, Mahalo engaged GMP Securities L.P. as its financial advisor to assist in seeking a sale of the assets of the Company, a sale or merger of the Company or a financial restructuring of the Company including raising new equity.

Despite engaging a financial advisor to meet this goal, the Company's efforts have not yielded any satisfactory alternatives and as such the Company expects that the full US$10 million fee will be payable on March 31, 2009. Additional information regarding the Amendment is available at www.sedar.com.

A majority of the Company's Canadian resource assets were sold by December 31, 2008; a small number of minor properties with aggregate production of approximately 80 boe per day remained to be disposed of as at December 31, 2008. During December 2008, production of natural gas from continuing operations was approximately 2,280 boe per day. At December 31, 2008, the Company had a working capital deficit of $91.9 million, including $75.1 million (US$61.3 million) of total loans outstanding under the Ableco credit facility. In addition, the Company has accrued an estimated liability of

$12.2 million (US$10.0 million) related to the Ableco Loan Fee. The Ableco bank debt has been classified as a current liability as a result of the Company's covenant breaches.

On March 5, 2009, Mahalo announced that it had received proposals from several qualified parties as a result of the process to seek strategic or refinancing alternatives. On the same date, Mahalo announced that it had received a reservation of rights letter from Ableco notifying the Company that it is in default under its loan agreement for failure to comply with certain covenants relating to obtaining a letter of intent ("**LOI**") for the sale or recapitalization of the company by March 1, 2009. As a result of the default, Ableco advised Mahalo that until resolved, future loans would be made in the sole discretion of the lender. To date, Ableco has not exercised its default-related rights or demanded repayment of the loan.

If Ableco were to call the debt, the Company would require an alternate credit facility and/or additional capital to discharge its obligations and continue its activities. The outcome of these matters is dependent on factors outside of the Company's control and cannot be predicted at this time. There can be no assurance that the Company's ongoing efforts will result in any change in the Company's current operations, that the Company can or will pursue any particular transaction or that any transaction will be concluded.

SIGNIFICANT ACQUISITIONS AND DISPOSITIONS

Other than the sale of the Company's Canadian assets as discussed above, the Company had no significant acquisition or dispositions in the year ended December 31, 2008.

RISK FACTORS

The following information is a summary only of certain risk factors relating to the activities of the Company and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this Annual Information Form.

Refinancing Risk

The Company currently has a US $105 million bank credit facility with a syndicate of two banks of which US $61.4 million is currently drawn.

The Company is required to comply with covenants under the credit facility. In the event that the Company does not comply with covenants under the credit facility, the Company's access to capital could be restricted or repayment could be required. The Company routinely reviews the covenants based on actual and forecast results and has the ability to make changes to its development plans to comply with covenants under the credit facility. Any of these events could affect the Company's ability to fund ongoing operations.

As at the date of this AIF, the Company is in default under its bank credit facility. As announced on March 5, 2008, Mahalo received a reservation of rights letter from Ableco notifying the Company that it is in default under its loan agreement for failure to comply with certain covenants. As a result of the default, Ableco advised Mahalo that until resolved, future loans would be made in the sole discretion of the lender. To date, Ableco has not exercised its default-related rights or demanded repayment of the loan.

If Ableco were to call the debt, the Company would require an alternate credit facility and/or additional capital to discharge its obligations and continue its activities. The outcome of these matters is dependent on factors outside of the Company's control and cannot be predicted at this time. There can be no assurance that the Company has sufficient assets or will be able to raise sufficient capital to make a full repayment to its Lenders if such an event were to occur. In addition, any financial restructuring plan ultimately agreed on by Mahalo and its Lenders may involve bankruptcy or similar filings by Mahalo and/or its subsidiary, Mahalo Energy (USA) Inc.

If Mahalo is unable to pay its debts when due, it may have to file for protection under the *Companies Creditors Arrangement Act,* the *Bankruptcy Insolvency Act* and/or the United States *Bankruptcy Act.* In the event the Company seeks protection under such legislation or it is forced into bankruptcy, the expenses of any such proceeding would reduce the assets available for payments to the Company's shareholders. In addition, the Company believes that the

filing by it for creditor protection or against it would not increase the amount of any payment or distribution that the shareholders would receive, could reduce such amount and, in any event, would delay receipt of any payment or distribution by such shareholders.

Going Concern

The Company's consolidated financial statements have been presented on the basis that the Company is a going concern, which presumes the realization of assets and discharge of liabilities in the normal course of business for the foreseeable future. However, significant conditions and events exist that cast doubt on the validity of this assumption.

The Company's ability to continue as a going concern is dependent upon its ability in the future to achieve profitable operations and, in the meantime, to obtain the necessary financing to meet its obligations and repay its liabilities arising from normal business operations when they become due. The future operation of the Company is dependant on its ability to successfully raise capital and receive the continued financial support from its Lenders. As at December 31, 2008, the Company had a working capital deficiency of $91.9 million and an accumulated deficit of $121.2 million. The Company requires additional funds to maintain operations and discharge liabilities as they become due. These conditions raise substantial doubt about the Company's ability to continue as a going concern.

In November 2008, the Company signed an amended bank credit agreement that resulted in an additional advance of US $5 million that is repayable on March 31, 2009. The amendment also requires the Company to pay a loan fee of between US $5 million and US $10 million on March 31, 2009, dependent upon achieving certain restructuring and/or refinancing initiatives. In conjunction therewith, the Company engaged GMP Securities L.P. to assist in seeking a sale of the assets of the Company, a sale or merger of the Company or a financial restructuring of the Company including raising new equity.

As of March 1, 2009, the Company was in breach of certain covenants under its bank credit agreement and does not expect to be in a position to repay the additional advance and pay the loan fee on March 31, 2009. The Company is currently working with its lenders to rectify this issue. If an acceptable solution is not achieved and the debt is called, the Company will require additional capital to continue its activities and discharge its obligations. The outcome of these matters is dependant on factors outside of the Company's control and cannot be predicted at this time.

Capital Markets

As a result of the weakened global economic situation, the Company, along with all other oil and gas entities, will have restricted access to capital and increased borrowing costs. The lending capacity of all financial institutions has diminished and risk premiums have increased independent of the Company's business and asset base. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Company's ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and the Company's securities in particular.

To the extent that external sources of capital become limited or unavailable or available on onerous terms, the Company's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result.

If cash flow from operations is lower than expected or capital costs for these projects exceed current estimates, or if the Company incurs major unanticipated expenses related to development or maintenance of its existing properties, it may be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for the Company's capital expenditure plans may result in a delay in development or production on the Company's properties.

Current Global Financial Conditions

Current global financial conditions have been subject to increased volatility and numerous financial institutions have either gone into bankruptcy or have had to be rescued by governmental authorities. Access to public financing has been negatively impacted by both sub-prime mortgages and the liquidity crisis affecting the asset-backed commercial paper market. These factors may impact the ability of Mahalo to obtain equity or debt financing in the future and, if obtained, on

terms favourable to Mahalo. If these increased levels of volatility and market turmoil continue, Mahalo's operations could be adversely impacted and the trading price of the common shares could be adversely affected.

General

Exploration for and development of oil and gas, including CBM and shale gas reservoirs involve many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. In the case of CBM and shale gas, there is no assurance that commercial quantities of natural gas can be extracted from shale formations or from coal packages especially with the commonly seen large quantities of produced water being witnessed prior to any gas flashing or gas break out occurring from the coal seams. Therefore there is no assurance that commercial quantities of CBM or shale gas can be discovered at economic rates.

Exploration, Development and Production Risks

The Company's operations are subject to the risks normally incidental to the operation and development of oil and gas and the drilling of oil and gas wells, including, but not limited to, encountering unexpected formation faults and pressures, pipe or cement failures, casing collapses, uncontrollable flows of underground natural gas, explosions, blow outs, surface cratering, fires, formation water and the release of contaminants into the environment. All of these potential occurrences could result in personal injuries, loss of life and substantial damage to oil and natural gas wells, production facilities and other property of the Company and others, as well as the imposition of significant fines and penalties pursuant to environmental legislation.

Mahalo may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Company.

The Company's oil and natural gas production operations are also subject to risks typically associated with such operations including premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on Mahalo.

The Company employs horizontal drilling technology and practices on a material volume of wells it drills and it must be understood that if Mahalo were to lose the horizontal drilling tools and mud motors below surface, the cost would be the Company's and this expense may be significant and could have a material adverse effect upon the Company's financial condition.

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Mahalo depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, Mahalo's existing reserves and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Mahalo's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that Mahalo will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, Mahalo may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by Mahalo.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. Limited access windows may also subject activities and projects to significant delays. While diligent well supervision and effective maintenance operations can

contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

The Company anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production of CBM or shale gas in the future. If the Company's revenues or reserves decline, the Company may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurances that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on the terms acceptable to the Company.

Risks Specific to Coalbed Methane

Although CBM exploration and development is subject to the same risks as in conventional oil and gas activity, it also has its own unique set of risks and challenges. Capital costs may be higher due to the complexity of multiple coal seams. In some cases, more wells may be required to effectively exploit the reserves in place. Lower wellhead pressures in CBM wells may require additional compression and larger flow lines.

CBM production often comes with water. In a sandstone or limestone reservoir, the gas molecules are between the rock particles. In coalbed, the gas molecules are stuck to the coal or adsorbed, and the spaces between the coals referred to as the "cleats", must be drained of water before gas will come out of the coal. The length of the dewatering process is different in each circumstance and can take over a year before CBM production begins. This means that any producer may have to put up with long lead times before seeing any cash flow from a project. The potentially large volumes of water can add operational complexity and concern such as freezing, scale formation and backpressure should pumping operations be inefficient. Disposal of water associated with any hydrocarbon production is generally very expensive and is subject to stringent government regulation in all areas of the Company's operation.

CBM development in Canada is in the early stages and as a result, may have its own unique set of risks and challenges from operational, economic, regulatory and other aspects. Since CBM development is new, companies drilling for or producing CBM are subject to higher levels of public scrutiny. Any problems experienced or thought to have been experienced by one company may adversely impact other CBM companies including Mahalo.

Speculative Nature of Exploratory and Developmental Oil and Natural Gas Activities

The Company's oil and natural gas exploration and development activities are focused on undeveloped oil and natural gas rights which are high-risk ventures with uncertain prospects for success. No assurance can be given that commercial accumulations of oil and natural gas will be discovered as a result of the efforts of the Company.

The Company's exploration and development activities depend in part on the evaluation of data obtained through geophysical testing and geological analysis. The results of such studies and tests are often subject to varying interpretations, and no assurances can be given that such activities will produce oil and natural gas in commercial quantities. Additional data required for proper evaluation becomes available only after drilling. The exploration and development activities are subject to greater risks than those normally associated with the acquisition and ownership of producing properties. The drilling of development wells, although generally consisting of drilling to reservoirs believed to be productive, may result in dry holes or a failure to produce oil and natural gas in commercial quantities. Moreover, any drilling of exploratory wells is subject to significant risk of dry holes.

The marketability of any oil and gas that may be discovered by the Company will be affected by numerous factors that cannot be predicted and that are beyond the control of the Company, including market fluctuations, the supply and demand for oil and natural gas, the proximity and capacity of pipelines, other forms of transport and processing equipment and government regulations, including regulations relating to the prices, taxes, royalties, land tenure, allowable production, the import and export of oil and natural gas and environmental protection. There is no guarantee that contracts for the sale or delivery of oil and natural gas will be obtainable or, if obtainable, will be on terms which are economically viable. These factors cannot be predicted.

There are numerous uncertainties inherent in estimating hydrocarbon reserve quantities and in projecting future rates of production, future development expenditures, costs to be incurred upon production and prices to be received upon sale and costs to be incurred upon production.

Operational Dependence

Other companies operate some of the assets in which Mahalo has an interest. As a result, Mahalo has limited ability to exercise influence over the operation of these assets or their associated costs, which could adversely affect Mahalo's financial performance. Mahalo's return on assets operated by others will therefore depend upon a number of factors that may be outside of Mahalo's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project Risks

Mahalo manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic.

Mahalo's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Company's control, including the availability of processing capacity; the availability and proximity of pipeline or other transport capacity; the supply of and demand for oil and natural gas; the availability of alternative fuel sources; the effects of inclement weather; the availability of drilling and related equipment; unexpected cost increases; accidental events; currency fluctuations; the availability and productivity of skilled labor; and regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, Mahalo could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Competition

The oil and gas industry is competitive in all its phases. Mahalo competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties, the marketing of oil and natural gas and technical and human resources. Mahalo's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than Mahalo. Mahalo's ability to increase reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery.

Regulatory

Oil and natural gas operations, including exploration, production, transportation and marketing are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for oil and natural gas and increase Mahalo's costs, any of which may have a material adverse effect on Mahalo's business, financial condition and results of operations. In order to conduct oil and gas operations, Mahalo requires licenses from various governmental authorities. There can be no assurance that Mahalo will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Kyoto Protocol

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger

fines and liability and potentially increased capital expenditures and operating costs. In 2002, the Government of Canada ratified the Protocol, which calls for Canada to reduce its greenhouse gas emissions to specified levels. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Protocol or as otherwise determined could have a material impact on the nature of oil and natural gas operations, including those of the Company. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on the Company and its operations and financial condition. The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and targeting research to lower the cost of technology.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require Mahalo to incur costs to remedy such discharge. Although Mahalo believes that it is in material compliance with current applicable environmental regulations no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Mahalo's financial condition, results of operations or prospects. See "Industry Conditions – Environmental Regulation".

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by Mahalo is and will continue to be affected by numerous factors beyond its control. Mahalo's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines or other forms of transport that deliver oil and natural gas to commercial markets. Mahalo may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines, other forms of transport and processing facilities and operational problems affecting such pipelines, other forms of transport and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of Mahalo's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of Mahalo's reserves. Mahalo might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Mahalo's net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. In addition, bank borrowings available to Mahalo are in part determined by Mahalo's borrowing base. A sustained material decline in prices from historical average prices could reduce Mahalo's borrowing base, therefore reducing the bank credit available to Mahalo which could require that a portion, or all, of Mahalo's bank debt be repaid and a liquidation of assets.

Substantial Capital Requirements

Mahalo anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If Mahalo's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if

debt or equity financing is available, that it will be on terms acceptable to Mahalo. The inability of Mahalo to access sufficient capital for its operations could have a material adverse effect on Mahalo's financial condition, results of operations and prospects.

Additional Funding Requirements

Mahalo's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, Mahalo may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause Mahalo to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. Mahalo's ability to expend the necessary capital to replace its reserves or to maintain its production could be impaired if Mahalo's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise. If Mahalo's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on acceptable terms.

Issuance of Debt

From time to time Mahalo may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase Mahalo's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, Mahalo may require additional equity and/or debt financing that may not be available or, if available, may not be available on favorable terms. Neither Mahalo's articles nor its by-laws limit the amount of indebtedness that Mahalo may incur. The level of Mahalo's indebtedness from time to time, could impair Mahalo's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Foreign Exchange Exposure

The Company conducts a significant portion of its operations in the United States. The Canadian to U.S. dollar exchange rate may fluctuate over time. Accordingly, a material decrease in the value of the U.S. dollar may negatively impact revenues from U.S. operations.

Hedging

From time to time Mahalo may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, Mahalo will not benefit from such increases. Similarly, from time to time Mahalo may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, Mahalo will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Mahalo and may delay exploration and development activities. To the extent Mahalo is not the operator of its oil and gas properties, Mahalo will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat Mahalo's claim which could result in a reduction of the revenue received by Mahalo.

Insurance

The Company always endeavours to be adequately insured; however, it is impossible to maintain a level of insurance coverage capable of dealing with every potential incident that could occur within an operation. In addition, the coverage obtained and/ or available may not be sufficient to cover the full extent of any resulting damage or liability. In certain circumstances, Mahalo may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons.

In accordance with industry practice, Mahalo is not fully insured against all risks, nor are all risks insurable. Although Mahalo maintains liability insurance in an amount that it considers adequate, the nature of these risks is such that liabilities could exceed policy limits, in which event Mahalo could incur significant costs that could have a material adverse effect upon its financial condition. The occurrence of a significant event that Mahalo is not fully insured against, or the insolvency of the insurer of such event, could also have a material adverse effect on Mahalo.

Dividends

To date, Mahalo has not declared or paid any dividends on the outstanding Common Shares. Any decision to pay dividends on the Common Shares will be made by the Board of Directors on the basis of Mahalo's earnings, financial requirements and other conditions existing at such future time. At present, Mahalo does not anticipate declaring and paying any dividends in the near future.

Conflicts of Interest

Certain directors of Mahalo are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA.

Reliance on Key Personnel

Mahalo's success depends in large measure upon the performance of its key personnel. Mahalo does not have any key man insurance in effect. The loss of the services of such key personnel could have a material adverse affect on Mahalo. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that Mahalo will be able to continue to attract and retain all personnel necessary for the ongoing development and operation of its business.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta and Oklahoma and the United States, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the Company's operations in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing of Oil and Natural Gas

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to the markets, the value of refined products, the supply/demand balance, and other contractual terms. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a

contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m3/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

The government of Alberta also regulates the volume of natural gas that may be removed from the province for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

Pipeline Capacity

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market natural gas production. In addition, the pro rationing of capacity on the inter provincial pipeline systems also continues to affect the ability to export oil and natural gas.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, United States of America, and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price subject to an exception with respect to certain voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, any prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import price requirements, such requirements do not apply with respect to enforcement of countervailing and anti dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur, and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, and the type or quality of the petroleum product produced. Other royalties and royalty like interests are, from time to time, carved out of the working interest owner's interest through non public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to eliminate, amend or allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

The Canadian federal corporate income tax rate levied on taxable income is 19.5% effective January 1, 2008 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008 and other rate reductions introduced in the October 2007 Economic Statement and Notice of Ways and Means Motion, 2006 Federal Budget, the federal corporate income tax rate will decrease to 15% in four additional steps: 19% on January 1, 2009, 18% on January 1, 2010, 16.5% on January 1, 2011 and 15% on January 1, 2012.

Alberta

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" (the "**NRF**") containing the Government's proposals for Alberta's new royalty regime, which was followed by the *Mines and Minerals (New Royalty Framework) Amendment Act*, 2008, which was given Royal Assent on December 2, 2008. The NRF and the applicable new legislation became effective on January 1, 2009. The NRF establishes new royalty rates for conventional oil, natural gas and oil sands. The new royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and increases the old royalty from 30% to 35% applied to the old and new tiers, to up to 50% and with rate caps once the price of conventional oil reaches $120 per barrel. The sliding rate formula includes in its calculation the price of oil and well production.

With respect to natural gas, and similar to the conventional oil framework, the royalties outlined in the NRF are set by a single sliding rate formula ranging from 5% to 50% with a rate cap once the price of natural gas reaches $16.59/GJ. In response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced on November 19, 2008, the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 metres) will be given a one-time option, on a well by well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. In order to qualify for this program wells must be drilled during the period starting on November 19, 2008 and ending on December 31, 2013. Following this period all new wells drilled will automatically be subject to the NRF.

On April 10, 2008, the Government of Alberta introduced two new royalty programs that will encourage the development of deep oil and gas reserves, and these are: (a) a five-year oil program for exploration wells over 2,000 metres that will provide royalty adjustments to offset higher drilling costs and provide a greater incentive for producers to continue to pursue new, deeper oil plays (these oil wells will qualify for up to a $1 million or 12 months of royalty offsets, whichever comes first); and (b) a five-year natural gas deep drilling program that will replace the existing program in order to encourage continued deep gas exploration for wells deeper than 2,500 metres (the program will create a sliding scale of royalty credit according to depth, of up to $3,750 per metre). These new programs are to be implemented along with the NRF.

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program was to be eliminated, effective January 1, 2007. The programs affected by this announcement were: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re Entry Royalty Reduction. The program introduced was the Innovative Energy Technologies Program (the "IETP") which has a stated objective of promoting the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy decides which projects qualify and the level of support that will be provided. The deadline for the IETP's final round of applications was September 20, 2008. The successful applicants for

the first two rounds have been announced, and those for the third round selection are scheduled to be announced in the first half of 2009. The technical information gathered from this program is to be made public once a two year confidentiality period expires.

The NRF includes a policy of "shallow rights reversion". The Government of Alberta started to implement this policy on January 1, 2009, and its intent is to maximize the development of currently undeveloped resources that is consistent with the Government of Alberta's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's stated objective is for the mineral rights to shallow gas geological formations that are not being developed to revert back to the Government and be made available for resale, and in the event of non-productive shallow wells, to sever the rights from shallow zones and encourage increased production from up-hole zones. The shallow rights reversion policy affects all petroleum and natural gas agreements; however, the timing of the reversion will differ depending on whether the leases and licenses were acquired prior to January 1, 2009 or subsequent to January 1, 2009. Leases granted after January 1, 2009 will be subject to shallow rights reversion at the expiry of the primary term, and in the event of a licence the policy will apply at the expiry of the intermediate term. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. The lease or licence holder can make a request to extend this period. The order in which these agreements will receive the reversion notice will depend on the vintage of their term, with the older leases and licenses receiving a reversion notice first. Leases or licences that were granted prior January 1, 2009 but have not yet been continued will have a grace period until they are continued under section 15 of the *P&G Tenure Regulation* and be subject to deeper rights reversion prior to receiving a shallow rights reversion notice.

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program a $200 per meter royalty credit will be available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, subject to certain maximum amounts. The maximum credits available will be determined by the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010. The new well incentive program will apply to wells beginning production of conventional oil and natural gas between April 1, 2009 and March 31, 2010 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels or 500 Mmcf of natural gas.

The three-point incentive program also includes an investment of $30,000,000 by the Government of Alberta in abandonment and reclamation projects for orphan wells. The stated objective of this investment is to encourage the cleanup of inactive oil and gas wells and to stimulate new activity within the services sector.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms from two years, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

Environmental legislation in Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the

"**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the *Climate Change and Emissions Management Amendment Act* came into effect on July 1, 2007 ("**CCEMAA**"). Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Industries can either choose one of these options or a combination thereof. Pursuant to CCEMAA and the Specified Gas Emitters Regulation, companies were obliged to reduce their emission intensity by 12% by March 31, 2008. Alberta industries have achieved 2.6 million tonnes of actual reduction, due to changes in operations and investing on verified offset projects. In addition, certain companies contributed $40 million to the Fund. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

On January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for in situ oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating carbon dioxide from other emissions supporting carbon capture and storage. In addition to this action plan, the Provincial Energy Strategy unveiled on December 11, 2008 is expected to, among other things, support the upgrading, refining and petrochemical clusters existing in the Province, market Alberta's energy internationally, review the emission targets and carbon charges applied to large facilities, and promote the innovation of energy technology by encouraging investment in research and development.

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"). The Kyoto Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business as usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. It is questionable, based on the Updated Action Plan announced by the Federal Government (see below), that the Kyoto Protocol target of 6% below 1990 emission levels will be enforced in Canada. Bill C 288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by the House of Commons on February 14, 2007. On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "**Action Plan**") also known as ecoACTION which includes the regulatory framework for air emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products.

The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

In order to strengthen the Action Plan, on March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the "**Updated Action Plan**") which provides some additional guidance with respect to the Government's plan to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050.

The Updated Action Plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and gas and refining. The Updated Action Plan is intended to create a carbon emissions trading market, including an offset system, to provide incentive to reduce greenhouse gas emission and establish a market price for carbon. There are mandatory reductions of 18% from the 2006 baseline starting in 2010 and an additional 2% in subsequent years for existing facilities. This target will be applied to regulated sectors on a facility-specific, sector-wide or corporate basis; in the case of oil sands production, petroleum refining, natural gas pipelines and upstream oil and gas the target will be considered facility-specific (sectors in which the facilities are complex and diverse, or where emissions are affected by factors beyond the control of the facility operator). Emissions from new facilities, which are those built between 2004 and 2011, will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time, and will be

granted a 3-year grace period during which no emissions intensity targets will apply. Targets will begin to apply on the fourth year of commercial operation and the baseline will be the third year's emissions intensity, with a 2% continuous annual emission intensity improvement required. The definition of new facility also includes greenfield facilities, major expansions constituting more than a 25% increase in a facility's physical capacity, as well as transformations to a facility that involve significant changes to its processes. For upstream oil and gas and natural gas pipelines, it will be applied using a sector-specific approach. For the oil sands, its application will be process-specific, oil sands plants built in 2012 and later, those which use heavier hydrocarbons, up-graders and in-situ production will have mandatory standards in 2018 that will be based on carbon capture and storage.

In the following regulated sectors, the Updated Action Plan will apply only to facilities exceeding a minimum annual emissions threshold: (i) 50,000 tonnes of CO2 equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO2 equivalent per upstream oil and gas facility; and (iii) 10,000 boe/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO2 equivalent per year per facility.

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund and for which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The contribution rate will increase over time, beginning at $15 per tonne for the 2010-12 period, rising to $20 per tonne in 2013, and thereafter increasing at the nominal rate of GDP growth. Contribution limits will correspondingly decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as mentioned above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either cancel the offset credits or bank them for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on the Company and its operations and financial condition at this time.

United States

In the United States, the oil and gas business is affected by numerous laws and regulations at the federal, state and local levels, including, among others, laws and regulations relating to energy, environment, conservation and tax. At present, the Company's United States operations are focused on CBM natural gas and shale gas and are located in the State of Oklahoma. In Oklahoma, the Corporation Commission controls oil and gas drilling activity, including CBM and shale gas. The Commission's responsibilities include the protection of correlative rights and the prevention of oil and gas waste.

The various laws and regulations include requiring permits for the drilling of wells; maintaining bonding requirements in order to drill or operate wells; implementing spill prevention plans; submitting notification and receiving permits relating to the presence, use and release of certain materials incidental to oil and gas operations; and regulating the location of wells, the method of drilling and casing wells, the use, transportation, storage and disposal of fluids and materials used in

connection with drilling and production activities, surface usage and the restoration of properties upon which wells have been drilled, the plugging and abandoning of wells and the transporting of production.

Oil and gas operations are subject to various conservation matters, including the regulation of the size of drilling and spacing units, the number of wells which may be drilled in a unit and the unitization or pooling of oil and gas properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases, which may make it more difficult to develop oil and gas properties. In addition, state conservation laws establish maximum rates of production from oil and gas wells, generally limit the venting or flaring of gas, and impose certain requirements regarding the rateable purchase of production. The effect of these regulations is to limit the amounts of oil and gas that can be produced from wells and to limit the number of wells or the locations that can be drilled.

Existing regulations designed to manage conventional natural gas development are applied to CBM and shale gas exploration and production; however, there are differences between conventional natural gas production and CBM that can include quality of produced water and well spacing. These differences have resulted in the drafting of CBM specific regulations by federal, state and local agencies. The handling and disposition of produced water has also resulted in additional regulatory oversight at the state level. This has included the oversight of CBM related activities by agencies that traditionally have not been involved in oil and gas related activities. Specifically, state laws with respect to maintaining acceptable water quality standards have emerged with respect to CBM.

Pricing and Production Taxes

The price of natural gas is determined by negotiation between buyers and sellers, often taking into account market index based prices for the commodity. The indices are generated at various points of sale and are reflective of the current value of the commodity adjusted for quality and location differentials. These differentials can change depending on supply demand fundamentals as well as other non-related changes such as the cost of transporting the commodity to the pricing point of the particular index.

The State of Oklahoma levies three taxes on natural gas production. They include a severance tax, called a "gross production tax" of 7.0 per cent and a production excise tax of 0.095 per cent of value at the point of production. A third tax is a gas conservation excise tax of US $0.07 cents per MCF of natural gas, subject to certain deductions. The gas conservation excise tax, however, is not triggered until the price of gas is below US $1.00 per MCF.

Environmental Regulation

Various federal, state and local laws and regulations concerning the discharge of incidental materials into the environment, the generation, storage, transportation and disposal of contaminants or otherwise relating to the protection of public health, natural resources, wildlife and the environment, affect oil and gas exploration, development, processing, and production operations and the costs attendant thereto. The Company is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws related to the protection of the environment.

North American Industry Trends

The supply demand balance for natural gas in North America has become extremely tight and as a result, the price for natural gas has been volatile over the last few years. Numerous factors affect natural gas supply and demand such as weather, consumption and storage levels, drilling activity, reserve declines and fuel switching. Management anticipates this pricing volatility will continue. Dramatic downward swings in the world prices for crude oil and natural gas could affect the economic viability of the Company's prospects.

Unlike crude oil prices, which are significantly influenced by global geopolitics, North American natural gas prices are primarily determined by consumer and industrial demand coupled with available supply. The North American natural gas market is highly integrated and Canada is the largest foreign natural gas supplier to the United States, supplying approximately 15 per cent of total United States natural gas demand. Constrained North American supply together with

growing demand is expected to support natural gas prices over the long-term; prices are however expected to remain volatile.

Canadian producers have responded to growing demand for natural gas with higher levels of drilling and by expanding their search for new sources of supply such as coalbed methane. According to the Canadian Association of Petroleum Producers, 15,895 natural gas wells were completed in 2005 in Western Canada, exceeding the record 15,041 wells drilled in 2004. By comparison, the average number of natural gas wells drilled between 1990 and 1999 was approximately 3,700 per year. Notwithstanding the increased level of drilling, North American natural gas production has not increased materially and exhibited successive years of decline in 2002 and 2003. The maturation of North American supply basins has resulted in declining well recoveries and higher production decline rates. Management expects that over the next several years Canada will remain the primary source of natural gas imports for the United States. While supply from non-conventional sources of natural gas such as liquefied natural gas and coalbed methane is becoming more prevalent, these sources are more costly than conventional sources and are not expected to have a material impact on the North American natural gas market for several years.

According to the U.S. Government Energy Information Administration, total natural gas consumption in 2008 and 2009 in the United States is projected to increase by 0.9% and 1.0%, respectively. Consumption growth in 2008 will be driven by the residential and commercial. Over the longer term, the Administration projects US total consumption of energy to grow by 0.9% annually between 2006 and 2030; natural gas consumption growth is projected at 0.3% annually during this period. An increasing level of US electricity generation is expected to be fuelled by natural gas because natural gas-fired generators typically have lower capital costs, lower emissions and higher fuel efficiency than coal-fired generators. In addition, the electricity generation sector is also looking to renewable sources of energy as a source of fuel.

Another trend is the volatility in external capital markets which impacts publicly traded entities, in the event that they seek to raise additional equity. In management's view, this can be partly attributed to uncertainty regarding the future growth prospects for world economies and to uncertainty regarding the future supply and demand for oil and gas. The competitive nature of the oil and gas industry will cause opportunities for equity financings to be selective. Some companies will have to rely on internally generated funds to conduct their exploration and developmental programs.

A trend within the Canadian oil and gas industry is the fairly consistent "renewal" of private and small junior oil and gas companies starting up business. These companies often have experienced management teams from previous industry organizations that have disappeared as a part of the ongoing industry consolidation. Many are able to recruit well qualified personnel. The Company must compete with these companies and others to attract qualified personnel.

An additional trend relates to the size of entities in which investors are willing to invest. Those with larger market capitalization may provide for greater liquidity and, as a result, appear to be more attractive during times of investor uncertainty.

Commodity prices realized by Canadian producers are heavily influenced by the U.S. dollar. The recent and significant increase in strength of the Canadian dollar has had a negative impact on Canadian oil and gas production revenue.

PRINCIPAL PROPERTIES

The following is a description of Mahalo's principal oil and natural gas properties as at December 31, 2008. The term "net", when used to describe Mahalo's share of production, means Mahalo's working interest share of production before deducting royalties owned by others. Unless otherwise specified, acreage, well count and production information are as at December 31, 2008. Reserves amounts are stated (before deduction of royalties) as at December 31, 2008, based on forecast costs and price assumptions and are derived from reserves information contained in the NSAI Report.

Canada

In 2008, the Company disposed of the majority of its Canadian properties and, as of the date hereof, only holds approximately 50 boe per day of production in Canada.

United States

Poteau

The Poteau CBM field is located in LeFlore County Oklahoma, which is approximately 80 miles southeast of Tulsa, Oklahoma. Production from this field is derived from the Pennsylvanian aged Hartshorne coal, which is approximately 2,000 feet deep in the area. CBM development in the Hartshorne formation is extensive in this part of the Arkoma Basin with many major independent producers active in the vicinity. Mahalo has a 65 per cent interest in 7,680 gross mineral acres with producing horizontal wells and producing verticals.

In 2008, the Company drilled 13 (8.4 net) CBM horizontal wells to maintain production levels. Current production from the field is approximately 4,000 Mcf (667 boe) of natural gas per day net to Mahalo. Produced gas from the area is delivered into the Center Point East pipeline system and sold to Oneok Energy Services Company LP of Tulsa, Oklahoma.

Island/Shelton

The Island/Shelton property is located in Pittsburgh County, Oklahoma, approximately 65 miles south of Tulsa. This property, which includes 15,452 gross acres of land, associated wells and facilities, has been producing since March, 2003. Mahalo acquired an approximate 23 per cent average working interest in the Island/Shelton acreage and producing wells in 2005. The majority of the production is from Hartshorne CBM wells and from McAlester CBM wells. Current production is approximately 595 Mcf (99 boe) of natural gas per day net to Mahalo. The gas from this area is sold to Oneok Energy Services Company LP of Tulsa, Oklahoma.

Lakeview

On November 2, 2005, Mahalo acquired the Lakeview property. Lakeview comprises Mahalo's largest property comprised 86,000 (33,000 net) acres of shallow rights and 94,000 (38,000 net) acres of deep rights with (net) producing wells as of December 31, 2008. Mahalo also has interests in three water disposal wells within the immediate area. Lakeview has demonstrated proven production of CBM, conventional natural gas and shale gas from multiple zones including the Hartshorne, Gilcrease, Jefferson, Caney and Woodford. The property is currently producing approximately 7,600 Mcf (1,267 boe) of natural gas per day net to the Company. The gas from the Lakeview area is gathered, transported and sold by means of four pipeline systems; namely Semgas, Enogex, Enerfin and Williams.

2009 Capital Spending Program

The Company has curtailed virtually all capital spending since late 2008 in order to reduce accounts payable and improve its financial position. As at the date of this AIF, the Company is in default under its bank credit facility agreement. Consequently, a 2009 capital spending program has not been developed.

STATEMENT OF RESERVES DATA

Disclosure of Reserves Data

The Statement of Reserves Data set forth below was prepared by the Company based on the NSAI Report. The NSAI Report is dated March 20, 2009, has an effective date of December 31, 2008 and was prepared December 2008 to January 2009. As of the preparation date, Netherland Sewell was not aware of any new information (other than commodity pricing assumptions which may differ from those used in their analysis), which could materially impact their evaluation.

The information set forth, which summarizes the oil and gas reserves of the Company and the net present values of future net revenue from those reserves is derived from the NSAI Report. The NSAI Report was prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook. The tables summarize and aggregate the data contained in the NSAI Report and, as a result, may contain slightly different numbers than the NSAI Report due to rounding. All evaluations of future net revenue are stated before and after the provision for income taxes and prior to indirect costs and after deduction of royalties, estimated future capital expenditures and well abandonment costs. It should not be assumed that the present values of estimated future net cash flows shown

below are representative of the fair market value of Mahalo's reserves. There is no assurance that the price and cost assumptions used in estimating such future net cash flows will be consistent with actual prices and costs and variances could be material. The recovery and reserve estimates of Mahalo's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater or less than the estimates provided herein.

In this Statement of Reserves Data, reference to "Natural Gas" includes non-associated, associated and solution gas. Certain columns in tables may not add due to rounding.

The Report of Mahalo Management and Directors on Oil and Gas Disclosure (on Form 51-101F3) and the Report on Reserves Data by Netherland Sewell (on Form 51-101F2) are included in this Annual Information Form.

SUMMARY OF RESERVES AND NET PRESENT VALUES OF ESTIMATED FUTURE NET REVENUE BASED ON FORECAST PRICES AND COSTS

Reserves Data as of December 31, 2008 (Canada and United States)

	CBM		Shale Gas		Natural Gas		Light and Medium Crude Oil	
Reserves Category	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MBbls)**	**Net (MBbls)**
Proved								
Developed Producing	28,389	22,703	1,323	1,052	243	371	121	113
Developed Non-Producing	898	717	-	-	-	-	25	25
Total Developed	29,287	23,420	1,323	1,052	243	371	146	138
Undeveloped	21,136	16,924	-	-	-	-	-	-
Total Proved	50,423	40,344	1,323	1,052	243	371	146	138
Probable	18,355	14,605	181	143	29	39	13	12
Total Proved plus Probable	68,778	54,949	1,504	1,195	272	410	159	150

Reserves Data as of December 31, 2008 (Canada)

	CBM		Shale Gas		Natural Gas		Light and Medium Crude Oil	
Reserves Category	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MBbls)**	**Net (MBbls)**
Proved								
Developed Producing	-	-	-	-	91	250	121	113
Developed Non-Producing	-	-	-	-	-	-	25	25
Total Developed	-	-	-	-	91	250	146	138
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	-	-	-	-	91	250	146	138
Probable	-	-	-	-	2	17	13	12
Total Proved plus Probable	-	-	-	-	93	267	159	150

Reserves Data as of December 31, 2008 (United States)

	CBM		Shale Gas		Natural Gas		Light and Medium Crude Oil	
Reserves Category	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MBbls)**	**Net (MBbls)**
Proved								
Developed Producing	28,389	22,703	1,323	1,052	152	121	-	-
Developed Non-Producing	898	717	-	-	-	-	-	-
Total Developed	29,287	23,420	1,323	1,052	152	121	-	-
Undeveloped	21,136	16,924	-	-	-	-	-	-
Total Proved	50,423	40,344	1,323	1,052	152	121	-	-
Probable	18,355	14,605	181	143	27	22	-	-
Total Proved plus Probable	68,778	54,949	1,504	1,195	179	143	-	-

Total Future Net Revenue Undiscounted as of December 31, 2008 (Canada and United States)

Reserves Category	**Revenue**	**Royalties**	**Operating Costs**	**Development Costs**	**Well Abandonment and Reclamation Costs**	**Future Net Revenue Before Income Taxes**	**Income Taxes**	**Future Net Revenue After Income Taxes**
				(Thousands of Dollars)				
Total Proved	589,892	143,358	162,243	42,758	5,852	235,681	63,462	172,219
Total Probable	237,500	61,397	74,088	26,114	1,563	74,339	18,965	55,374
Total Proved plus Probable	827,392	204,755	236,331	68,872	7,415	310,020	82,427	227,593

Total Future Net Revenue Undiscounted as of December 31, 2008 (Canada)

Reserves Category	**Revenue**	**Royalties**	**Operating Costs**	**Development Costs**	**Well Abandonment and Reclamation Costs**	**Future Net Revenue Before Income Taxes**	**Income Taxes**	**Future Net Revenue After Income Taxes**
				(Thousands of Dollars)				
Total Proved	13,916	(539)	8,336	60	581	5,478	-	5,478
Total Probable	1,513	(101)	773	-	15	825	-	825
Total Proved plus Probable	15,429	(640)	9,109	60	596	6,303	-	6,303

Total Future Net Revenue Undiscounted as of December 31, 2008 (United States)

Reserves Category	**Revenue**	**Royalties**	**Operating Costs**	**Development Costs**	**Well Abandonment and Reclamation Costs**	**Future Net Revenue Before Income Taxes**	**Income Taxes**	**Future Net Revenue After Income Taxes**
				(Thousands of Dollars)				
Total Proved	575,976	143,897	153,907	42,698	5,271	230,203	63,462	166,741
Total Probable	235,987	61,498	73,315	26,114	1,547	73,513	18,965	54,548
Total Proved plus Probable	811,963	205,395	227,222	68,812	6,818	303,716	82,427	221,289

Net Present Values of Future Net Revenue as of December 31, 2008 (Canada and United States)

Reserves Category	Before Income Taxes – Discounted at %/year					After Income Taxes – Discounted at %/year				
	0	5	10	15	20	0	5	10	15	20
	(Thousands of Dollars)					(Thousands of Dollars)				
Proved										
Developed Producing	157,666	115,675	92,098	77,388	67,422	115,609	96,610	79,511	68,438	60,683
Developed Non-Producing	4,111	3,013	2,332	1,880	1,564	3,080	2,464	1,959	1,615	1,368
Total Developed	161,777	118,688	94,430	79,268	68,986	118,689	99,074	81,470	70,053	62,051
Undeveloped	73,904	38,322	19,830	9,381	3,078	53,530	19,959	7,888	1,034	(3,097)
Total Proved	235,681	157,010	114,260	88,649	72,064	172,219	119,033	89,358	71,087	58,954
Probable	74,338	34,003	16,979	8,640	4,057	55,373	23,949	10,515	4,096	734
Total Proved plus Probable	310,019	191,013	131,239	97,289	76,121	227,592	142,982	99,873	75,183	59,688

Net Present Values of Future Net Revenue as of December 31, 2008 (Canada)

Reserves Category	Before Income Taxes – Discounted at %/year					After Income Taxes – Discounted at %/year				
	0	5	10	15	20	0	5	10	15	20
	(Thousands of Dollars)					(Thousands of Dollars)				
Proved										
Developed Producing	5,109	3,584	2,780	2,283	1,942	5,109	3,584	2,780	2,283	1,942
Developed Non-Producing	369	285	223	177	142	369	285	223	177	142
Total Developed	5,478	3,869	3,003	2,460	2,084	5,478	3,869	3,003	2,460	2,084
Undeveloped	-	-	-	-	-	-	-	-	-	-
Total Proved	5,478	3,869	3,003	2,460	2,084	5,478	3,869	3,003	2,460	2,084
Probable	825	403	242	166	123	825	403	242	166	123
Total Proved plus Probable	6,303	4,272	3,245	2,626	2,207	6,303	4,272	3,245	2,626	2,207

Net Present Values of Future Net Revenue as of December 31, 2008 (United States)

Reserves Category	Before Income Taxes – Discounted at %/year					After Income Taxes – Discounted at %/year				
	0	5	10	15	20	0	5	10	15	20
	(Thousands of Dollars)					(Thousands of Dollars)				
Proved										
Developed Producing	152,557	112,093	89,314	75,100	65,474	110,501	93,026	73,731	66,155	58,741
Developed Non-Producing	3,742	2,728	2,110	1,706	1,425	2,710	2,178	1,736	1,438	1,225
Total Developed	156,299	114,821	91,424	76,806	66,899	113,211	95,204	78,467	67,593	59,966
Undeveloped	73,904	38,322	19,830	9,381	3,078	53,530	19,959	7,888	1,034	(3,097)
Total Proved	230,203	153,143	111,254	86,187	69,977	166,741	115,163	86,355	68,627	56,869
Probable	73,513	33,611	16,744	8,474	3,933	54,548	23,545	10,273	3,930	611
Total Proved plus Probable	303,716	186,754	127,998	94,661	73,910	221,289	138,708	96,628	72,557	57,480

Future Net Revenue by Production Group as of December 31, 2008

Reserves Category	Production Group	Future Net Revenues Before Income Taxes – Discounted at 10%/year	Unit Value Before Income Tax-Discounted at 10%/year ($/Mcf) ($/Bbl)
		(Thousands of Dollars)	
Proved	CBM	108,415	2.15
	Shale Gas	2,635	1.99
	Natural Gas	1,310	5.39
	Light and Medium Crude Oil	1,900	11.47
Proved plus Probable	CBM	124,814	1.81
	Shale Gas	2,946	1.96
	Natural Gas	1,364	5.01
	Light and Medium Crude Oil	2,111	11.73

Summary of Pricing and Inflation Rate Assumptions as at December 31, 2008

	Oil			Natural Gas		Edmonton Liquids Prices				
Year	WTI Cushing Oklahoma (US$/bbl)	Edmonton Par Price 40° API (Cdn$/bbl)	Hardisty Heavy 12° API (Cdn$/bbl)	Henry Hub (US$/MMBtu)	AECO Gas Price (Cdn$/MMBtu)	Propane (Cdn$/bbl)	Butane (Cdn$/bbl)	Pentanes Plus (Cdn$/bbl)	Inflation Rate [(2)] %/Year	Exchange Rate[(3)] (US$/Cdn$)
Forecast										
2009	53.73	65.35	47.05	7.80	6.82	40.70	51.15	66.93	2.0	0.8166
2010	63.41	72.78	54.58	6.89	7.56	43.16	54.25	74.54	2.0	0.8166
2011	69.53	79.95	59.96	7.56	7.84	47.42	59.59	81.88	2.0	0.8166
2012	79.59	86.57	67.53	8.49	8.38	51.34	64.53	88.66	2.0	0.8166
2013	92.01	94.97	74.08	9.74	9.20	56.33	70.79	97.27	2.0	0.8166
2014	93.85	96.89	75.58	9.94	9.41	57.46	72.22	99.23	2.0	0.8166
2015	95.72	98.85	77.10	10.14	9.62	58.62	73.68	101.23	2.0	0.8166
2016	97.64	100.84	78.66	10.34	9.83	59.81	75.16	103.28	2.0	0.8166
2017	99.59	102.88	80.25	10.54	10.05	61.02	76.68	105.36	2.0	0.8166
Thereafter					+2.0% per year					

Notes:

(1) The forecast price and cost assumptions assume the continuance of current laws and regulations and increases in wellhead selling prices, and take into account inflation with respect to future operating capital costs. If not otherwise stated in the NSAI Report, operating costs are assumed to escalate at 2% per annum.

(2) Inflation rates for forecasting prices and costs.

(3) Exchange rates used to generate the benchmark reference prices in this table.

(4) The Henry Hub prices for 2009 and 2010 include the effects of current hedging contracts in place.

Reconciliation of Changes in Gross Reserves and by Principal Product Type (Canada)[(1)(2)]

	CBM			Shale Gas			Natural Gas			Light and Medium Crude Oil		
Factors	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved plus Probable (MMcf)**	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved plus Probable (MMcf)**	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved plus Probable (MMcf)**	**Gross Proved (MBbls)**	**Gross Probable (MBbls)**	**Gross Proved plus Probable (MBbls)**
December 31, 2007	3,744	4,863	8,607	-	-	-	8,595	2,816	11,411	162	13	175
Extensions	-	-	-	-	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	338	(3)	335	-	-	-	(324)	12	(312)	54	(2)	52
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	(3,714)	(4,860)	(8,574)	-	-	-	(6,173)	(2,698)	(8,871)	-	-	-
Economic Factors	-	-	-	-	-	-	(366)	(110)	(475)	(45)	2	(43)
Production	(368)	-	(368)	-	-	-	(1,472)	-	(1,472)	(26)	-	(26)
December 31, 2008	0	-	0	-	-	-	261	20	282	145	13	159

Reconciliation of Changes in Gross Reserves and by Principal Product Type (United States)[(1)(2)]

	CBM			Shale Gas			Natural Gas			Light and Medium Crude Oil		
Factors	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved plus Probable (MMcf)**	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved plus Probable (MMcf)**	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved plus Probable (MMcf)**	**Gross Proved (MBbls)**	**Gross Probable (MBbls)**	**Gross Proved plus Probable (MBbls)**
December 31, 2007	46,877	18,672	65,549	1,171	266	1,437	1,253	-	1,253	-	-	-
Extensions	9,583	5,085	14,668	16	32	48	7	-	7	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	(48)	(4,862)	(4,910)	145	(117)	28	(918)	44	(874)	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	(1,424)	(540)	(1,965)	(2)	(1)	(3)	(45)	(17)	(62)	-	-	-
Production	(4,565)	-	(4,565)	(6)	-	(6)	(144)	-	(144)	-	-	-
December 31, 2008	50,423	18,355	68,778	1,324	180	1,504	153	27	179	-	-	-

Notes:

(1) "**Gross reserves**" means the Company's working interest reserves before calculation of royalties and before consideration of the Company's royalty interests.

(2) These tables were prepared by the Company based on information in the NSAI Report and in accordance with the requirements under NI 51-101 that reserves be disclosed by country.

Undeveloped Reserves

Proved Undeveloped Reserves

Year	CBM (MMcf)		Shale Gas (MMcf)		Natural Gas (MMcf)		Light and Medium Crude Oil (Mbbl)	
	First Attributed	Year End Total	First Attributed	Year End Total	First Attributed	Year End Total	First Attributed	Year End Total
2006	5,172	14,402	-	-	993	1,238	-	274
2007	14,402	24,469	-	-	1,238	1,826	274	24
2008	24,469	21,136	-	-	1,826	-	24	-

Probable Undeveloped Reserves

Year	CBM (MMcf)		Shale Gas (MMcf)		Natural Gas (MMcf)		Light and Medium Crude Oil (Mbbl)	
	First Attributed	Year End Total	First Attributed	Year End Total	First Attributed	Year End Total	First Attributed	Year End Total
2006	10,371	14,627	-	-	408	896	-	321
2007	14,627	18,933	-	-	896	2,023	321	-
2008	18,933	18,355	-	-	2,023	-	-	-

In general, once proved and/or probable undeveloped reserves are identified, they are integrated into Mahalo's development plans. The Company's business plan generally envisions the development of proved and probable undeveloped reserves within two years of the date of such integration. The various factors that could result in delayed or cancelled development include:

- changing economic conditions;
- changing technical conditions (production anomalies (i.e., water breakthrough, accelerated depletion));
- multi-zone developments (i.e. a prospective formation completion may be delayed until the initial completion is no longer economic);
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and
- surface access issues (landowners, weather conditions and regulatory approvals, for example).

Future Development Costs

The following table sets forth estimated future development costs deducted by Netherland Sewell in the estimation of the future net revenue attributable to the reserve categories noted below.

Year	Forecast Prices and Costs Proved			Forecast Prices and Costs Proved plus Probable		
	Canada	United States	Total	Canada	United States	Total
	(Thousands of Dollars)			(Thousands of Dollars)		
2009	60	8,684	8,744	60	10,487	10,547
2010	-	17,077	17,077	-	22,289	22,289
2011	-	14,036	14,036	-	24,514	24,514
2012	-	2,901	2,901	-	11,523	11,523
2013	-	-	-	-	-	-
Remainder	-	-	-	-	-	-
Total Undiscounted	60	42,698	42,758	60	68,813	68,873

In all years for which economic forecasts were made by Netherland Sewell in the NSAI Report, the net revenues from the reserves are well in excess of the estimated future development costs. Therefore, the NSAI Report assumes that the Company will be able to fund the anticipated expenditures for future development entirely out of its cash flow and will not require other sources in order to develop the proved or probable reserves. As a result, interest or other costs of external funding are not included in the reserves and future net revenue estimates.

Significant Factors or Uncertainties

Other than the various risks and uncertainties that participants in the oil and gas industry are exposed to generally, Mahalo is unable to identify any important economic factors or significant uncertainties that will affect any particular components of the reserves data disclosed herein. See "Risk Factors".

OTHER OIL AND GAS INFORMATION

Landholdings

Mahalo's developed and undeveloped landholdings in acres as at December 31, 2008, are set forth in the following table.

	Developed		Undeveloped		Total	
	Gross [1]	Net [2]	Gross [1]	Net [2]	Gross [1]	Net [2]
Canada	16,297	13,358	43,634	36,098	59,931	49,456
United States						
Shallow rights	47,533	18,986	72,267	26,450	119,800	45,436
Deep rights	32,012	8,892	72,514	34,524	104,526	43,416

Notes:
(1) "**Gross**" means, collectively, the total area of properties, in acres, in which the Company has an interest.
(2) "**Net**" means, collectively, the total area of properties, in acres, in which the Company has an interest multiplied by the working interest owned by the Company.

In the United States, in certain sections of Mahalo's lands, both deep and shallow opportunities are present. Therefore, the land base is more practically split into shallow and deep rights. The above table sets forth developed and undeveloped acreage for the shallow coalbed methane plays and the deeper shale gas plays. The shallow and deep plays are based on a stratigraphic split, and often overlap each other on a geographic basis. As such, the sum of the shallow and deep mineral acres will exceed the total on a surface acreage basis.

The Company expects that rights to explore develop and exploit approximately 2,012 net acres of undeveloped landholdings attributable to Mahalo's properties and assets could expire by December 31, 2009. However, the Company's 2009 exploration and development activities may defer the expiry of a portion of these lands.

Exploration and Development Activities

The following table sets out the number of gross and net wells in which Mahalo participated during the year ended December 31, 2008.

	2008					
	Exploratory Wells		Development Wells		Total Wells	
	Gross [1]	Net [2]	Gross [1]	Net [2]	Gross [1]	Net [2]
Crude Oil - Canada	-	-	-	-	-	-
Natural Gas - Canada	-	-	1	1.0	1	1.0
Natural Gas - United States	4	1.1	67	34.9	71	36.0
Dry - Canada	1	1.0	1	1.0	2	2.0
Dry - United States	-	-	2	0.0	2	0.0
Total	5	2.1	71	36.9	76	39.0
Average working interest		42%		52%		51%
Success rate		52%		97%		95%

Notes:
(1) "**Gross**" means the total number of wells in which the Company has an interest.
(2) "**Net**" means the number of wells obtained by aggregating the Company's working interest in each of the gross wells.
(3) For the Company's 2009 planned Exploration and Development Activities, see "Principal Properties".

Oil and Gas Properties and Wells

The following table illustrates the number and status of wells in which Mahalo has an interest as at December 31, 2008, which are producing or which the Company considers to be capable of production. The Company did not have other significant plants, facilities and installations at December 31, 2008.

	Producing Wells							
	CBM		Shale Gas		Natural Gas		Light and Medium Crude Oil	
	Gross [1]	Net [2]	Gross [1]	Net [2]	Gross [1]	Net [2]	Gross [1]	Net [2]
Canada	-	-	-	-	24	1.0	13	12.0
United States	204	99.0	25	12.0	5	2.0	-	-

	Shut-In Wells[3]							
	CBM		Shale Gas		Natural Gas		Light and Medium Crude Oil	
	Gross [1]	Net [2]	Gross [1]	Net [2]	Gross [1]	Net [2]	Gross [1]	Net [2]
Canada	19	19.0	-	-	8	8.0	21	18.0
United States	3	0.6	7	4.2	2	0.8	-	-

Notes:

(1) "**Gross**" refers to all wells in which Mahalo has a working interest.

(2) "**Net**" refers to the aggregate of the percentage working interests of Mahalo in the gross wells, before the deduction of royalties.

(3) "**Shut-in Wells**" refers to wells that are capable of producing crude oil or natural gas, but which are not producing due to lack of available transportation facilities, available markets or other reasons. Shut-in wells in which Mahalo has an interest are located no further than 10 kilometres from existing pipelines.

(4) All of the wells reflected in the table above are onshore. All of the Canadian wells are in Alberta, except for 6 oil wells in Saskatchewan. All of the United States wells are in the state of Oklahoma.

Capital Expenditures

The following table sets out Mahalo's 2008 net capital expenditures by expenditure category.

	Year Ended December 31, 2008		
	Canada	United States	Total
	(Thousands of Dollars)		
Land and seismic	1,665	6,901	8,566
Drilling and completions	3,967	27,022	30,989
Facilities and equipment	1,063	8,203	9,266
Property divestures	(18,689)	-	(18,689)
Total	(11,994)	42,126	30,132

Production History and Netback Analysis

The following tables sets forth certain information in respect of sales volumes, realized product prices, royalties paid, and operating and transportation expenses and resulting netback by quarter and for full year 2008 for Canada and the United States.

Canada

	2008			
	Mar. 31	June 30	Sept. 30	Dec. 31
Average Daily Sales Volume[1]				
CBM (Mcf/day)	1,195	1,062	853	316
Natural Gas (Mcf/day)	6,574	5,954	3,971	438
Light and Medium Crude Oil (Bbl/day)	59	84	66	75
Combined (boe/day)	1,354	1,254	870	200
Average Price Received				
CBM ($/Mcf)	7.39	10.31	8.22	7.59
Natural Gas ($/Mcf)	7.38	9.58	8.06	18.19
Light and Medium Crude Oil (Bbl/day)	77.32	108.44	117.45	54.07
Combined ($/boe)	45.75	61.54	53.72	71.92

Canada

	2008			
	Mar. 31	June 30	Sept. 30	Dec. 31
Royalties Paid				
CBM ($/Mcf)	2.24	6.35	2.29	1.68
Natural Gas ($/Mcf)	1.87	0.81	1.15	3.75
Light and Medium Crude Oil (Bbl/day)	7.00	16.43	(0.86)	(1.00)
Combined ($/boe)	11.30	10.32	7.41	10.69
Operating and transportation expense				
CBM ($/Mcf)	2.36	5.39	5.00	9.08
Natural Gas ($/Mcf)	1.46	0.50	2.70	10.86
Light and Medium Crude Oil (Bbl/day)	24.77	55.57	44.08	39.16
Combined ($/boe)	10.26	10.68	20.54	52.69
Netback Received [(2)]				
CBM ($/Mcf)	2.79	(1.43)	0.93	(3.17)
Natural Gas ($/Mcf)	4.05	8.27	4.21	3.58
Light and Medium Crude Oil (Bbl/day)	45.55	36.44	74.23	15.91
Combined ($/boe)	24.19	40.54	25.77	8.54

United States

	2008			
	Mar. 31	June 30	Sept. 30	Dec. 31
Average Daily Sales Volume [(1)]				
CBM (Mcf/day)	11,277	10,864	12,447	13,075
Shale Gas (Mcf/day)	309	670	366	519
Natural Gas (Mcf/day)	704	632	335	324
Combined (boe/day)	2,048	2,028	2,191	2,320
Average Price Received				
CBM ($/Mcf)	6.92	8.36	7.51	8.67
Shale Gas ($/Mcf)	6.77	7.64	13.48	8.32
Natural Gas ($/Mcf)	7.59	8.48	13.67	8.49
Combined ($/boe)	41.74	49.93	47.01	51.92
Royalties Paid				
CBM ($/Mcf)	1.87	2.34	1.98	2.29
Shale Gas ($/Mcf)	0.44	0.50	0.90	0.54
Natural Gas ($/Mcf)	0.48	0.54	0.88	0.52
Combined ($/boe)	10.52	12.86	11.54	13.11
Operating and transportation expense				
CBM ($/Mcf)	0.91	1.49	1.91	1.86
Shale Gas ($/Mcf)	11.52	6.82	8.88	7.36
Natural Gas ($/Mcf)	1.78	2.05	4.50	3.35
Combined ($/boe)	7.38	10.86	13.01	12.62
Netback Received [(2)]				
CBM ($/Mcf)	4.14	4.53	3.62	4.52
Shale Gas ($/Mcf)	(5.19)	0.32	3.70	0.42
Natural Gas ($/Mcf)	5.33	5.89	8.29	4.62
Combined ($/boe)	23.84	26.21	22.46	26.19

Notes:

(1) Before deduction of royalties. Natural gas is converted to a barrel of oil equivalent on the basis of 6 Mcf = 1 bbl.

(2) Netback is calculated by deducting royalties, operating and transportation costs from sales and revenues. Sales revenues do not include gains or losses on financial derivative contracts.

Forward Contracts

The following summary of the commodity physical fixed price sale commitments outstanding as of the date of this AIF.

Transaction	Daily Volume	Contract Price	Term
	(MMBtu)		
Sell	3,000	US $10.22/MMbtu	November 2008 – June 2009
Sell	2,750	US $10.35/MMbtu	November 2008 – June 2009
Sell	1,000	US $10.26/MMbtu	November 2008 – July 2009
Sell	2,000	Pan Index + US $0.01/MMbtu	January 2009 – June 2009
Sell	5,000	Pan Index + US $0.05/Mmbtu	July 2009 – May 2010
Sell	3,000	Pan Index + US $0.01/Mmbtu	January 2009 – December 2009
Sell	2,000	Pan Index Flat	July 2009 – December 2009

As at the date of this AIF, the Company had the following financial derivative contracts outstanding

Transaction	Daily Volume	Contract Price	Term
	(MMBtu)		
Sell – NYMEX Financial Fixed Price	5,000	US $7.44/MMbtu	January 2009 – December 2009
Sell – NYMEX Financial Fixed Price	2,500	US $8.10/MMbtu	January 2010 – December 2010
Sell – Financial Panhandle Basis	5,000	HH minus US $1.12/MMBtu	July 2009 – May 2010
Sell – Financial Panhandle Basis	5,000	HH minus US $1.27/MMBtu	January 2009 – December 2009
Sell – Financial Panhandle Basis	2,500	HH minus US $0.98/MMBtu	January 2010 – December 2010
Sell – Financial Panhandle Basis	2,500	HH minus US $1.00/MMBtu	January 2010 – December 2010

In addition to the above, the Company entered into a participating natural gas financial derivative swap contract whereby the Company will receive a floor price of US $10/Mmbtu for 5,000 Mmbtu/day and will participate for 31 percent of the price in excess of US $10/Mmbtu. The term is from July 2009 to May 2010.

Additional Information Concerning Abandonment and Reclamation Costs

Mahalo estimates the costs to abandon and reclaim all its shut in and producing wells, facilities, gas plants, pipelines, batteries and satellites. As at December 31, 2008, Mahalo had interests in 208.6 net wells. Mahalo's model for estimating the amount and timing of future abandonment and reclamation expenditures was done on an operating area level. Estimated expenditures for each operating area in Canada were based on the AEUB methodology, which details the cost of abandonment and reclamation in each specific geographic region. Each region was assigned an average cost per well to abandon and reclaim the wells in that area. Facility reclamation costs are scheduled to be incurred in the year following the end of the reserve life of its associated reserves. Abandonment costs in the United States were based on average reported abandonment costs for the Arkoma basin.

As at December 31, 2008, the Company estimated that the future abandonment and reclamation obligations, escalated at 2 per cent per year, in respect of its properties and assets will aggregate approximately $7.2 million (without discount) and $2.4 million discounted at 10 per cent. The Company does not expect to incur any of these costs in the next three financial years.

The Company will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the properties held by it upon abandonment. Ongoing environmental obligations are expected to be funded out of cash flow.

The estimated amounts for future abandonment and reclamation of $7.2 million (undiscounted) that have not been deducted in estimating the future net revenue from proved reserves disclosed elsewhere in this document are $1.3 million on an undiscounted basis and $1.3 million on a discounted basis.

Tax Horizon

Mahalo's management presently anticipates that it will not be taxable in Canada for the next three years. Mahalo has estimated that Canadian and United States tax pools of approximately Cdn $68 million and US $107 million, respectively, are available as at December 31, 2008, which can be used to off-set taxable income in future years. In the U.S., Mahalo expects it will be subject to franchise taxes of $20,000 in both 2009 and 2010. The estimates do not take into account additional income tax pools that would result from future capital programs or the income that may result from such capital programs.

Production Estimates

The following table sets out the volume of the proved plus probable gross production estimated for the year ending December 31, 2009 which is reflected in the estimate of future net revenue disclosed in the tables contained under "Disclosure of Reserves Data".

Country	CBM (MMcf)	Shale Gas (MMcf)	Natural Gas (MMcf)	Crude Oil (MBbls)
Canada	-	-	8	17
United States	4,437	285	24	-
Total	4,437	285	32	17

Note:

(1) "**Gross production**" means the company interest in sales volumes as defined in the NSAI Report.

(2) In the United States, the Poteau field accounts for approximately 35 percent and the Lakeview field accounts for approximately 60 percent of the total estimated CBM, shale gas and natural gas production reflected in the above table.

Additional notes:

In the tables set forth above and elsewhere in this Annual Information Form, the following definitions and other notes are applicable,

(3) Columns in certain tables may not add due to rounding.

(4) "**Gross**" means Mahalo's total working interest and/or royalty interest share before royalties owned by others.

(5) "**Net**" or "**net**" means Mahalo's total working interest and/or royalty interest share after deducting the amounts attributable to royalties owned by others.

(6) "**Royalties**" refers to royalties paid to others. The royalties deducted from the reserves are based on the percentage royalty calculated by applying the applicable royalty rate or formula. In the case of Crown sliding scale royalties, which are dependent on selling prices, the price forecasts for the individual properties in question have been employed.

(7) "**Reserves**" are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates.

(8) "**Proved Reserves**" are those Reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves. At least a 90% probability that the quantities actually recovered will equal or exceed the estimated Proved Reserves, on an aggregate basis, is the targeted level of certainty.

(9) "**Probable Reserves**" are those additional Reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable Reserves. At least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable Reserves, on an aggregate basis, is the targeted level of certainty.

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

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

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

(13) "**Undeveloped Reserves**" are those Reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the Reserves classification (proved, probable, possible) to which they are assigned. The extent and character of all factual data supplied to Netherland Sewell was accepted by Netherland Sewell as represented. The crude oil and natural gas reserve calculations and any projections upon which the NSAI Report are based were determined in accordance with generally accepted evaluation practices. No field inspections were conducted. Salvage values for facilities and base reclamation costs for any of the Company's wells which were assigned no reserves have not been included in the NSAI Report. No costs were included in the NSAI Report for the abandonment of surface facilities or gathering systems or for the reclamation of surface leases.

(14) Estimated future abandonment and reclamation costs related to a property have been taken into account by Netherland Sewell in determining reserves that should be attributed to a property, and, in determining the aggregate future net revenue therefrom, Netherland Sewell deducted the reasonable estimated future well abandonment costs.

DIVIDEND HISTORY

To date, Mahalo has not declared or paid any dividends on the outstanding Common Shares. Any decision to pay dividends on the Common Shares will be made by the Board of Directors on the basis of Mahalo's earnings, financial requirements and other conditions existing at such future time. At present, Mahalo does not anticipate declaring and paying any dividends in the near future.

DESCRIPTION OF CAPITAL STRUCTURE

The Company is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred shares (the "Preferred Shares"). As at March 31, 2009, there were 59,298,035 Common Shares and no Preferred Shares issued and outstanding. In addition, as at such date, there were an aggregate of 4,104,732 Common Shares reserved for issuance upon the exercise of outstanding options to purchase Common Shares and 1,440,000 Performance Warrants.

The following is a summary of the rights, privileges, restrictions and conditions attaching to each class of shares of the Company. Documents affecting the rights of security holders, including the Company's Articles, have been filed in accordance with NI 51-102 and are available on the Company's SEDAR profile at www.sedar.com.

Common Shares

Mahalo is authorized to issue an unlimited number of Common Shares without nominal or par value. Holders of Common Shares are entitled to one vote per share at meetings of shareholders of Mahalo, except meetings of another class or series of shares of Mahalo, which are required by law to be held separately. Subject to the rights of the holders of any other shares having priority over the Common Shares, holders of Common Shares are entitled to dividends if, as and when declared by the Board of Directors and, upon liquidation, dissolution or winding-up, to receive the remaining property of Mahalo.

Preferred Shares

Mahalo is authorized to issue an unlimited number of Preferred Shares. The Preferred Shares may be issued from time to time in one or more series, each series consisting of the number of shares and having the designation, rights, privileges, restrictions and conditions which the Board of Directors of the Company determines prior to the issue thereof. The Preferred Shares rank prior to the Common Shares with respect to the payment of dividends and distribution in the event of liquidation, dissolution or winding-up of the Company.

MARKET FOR SECURITIES

The Common Shares of the Company trade on the TSX under the symbol "CBM". The following table sets forth the price range and the volume of the Common Shares as reported by the TSX.

	High	Low	Close	Volume
2008				
January	$2.84	$2.12	$2.28	2,453,085
February	$2.95	$2.26	$2.70	1,845,553
March	$2.85	$2.25	$2.47	4,504,603
April	$2.65	$2.05	$2.40	3,102,248
May	$2.82	$2.34	$2.70	1,983,751
June	$2.78	$2.56	$2.65	2,596,457
July	$2.71	$2.26	$2.26	1,088,826
August	$2.39	$1.95	$2.25	1,229.564
September	$2.43	$1.10	$1.20	1,001,286
October	$1.28	$0.20	$0.22	3,263,623
November	$0.34	$0.16	$0.16	911,564
December	$.012	$0.02	$0.04	12,385,580

ESCROWED SECURITIES

No securities of the Company, to the Company's knowledge, are held in escrow as of the date hereof.

DIRECTORS AND OFFICERS

The names, municipality of residence, the offices held by each in the Company, and the principal occupation of the directors and officers, the period served as director and the number of securities of the Company owned by such individuals as at March 31, 2009 is as follows:

Name and Place of Residence	Positions with Mahalo [1]	Director Since	Number and Percentage of Common Shares Owned	Principal Occupation and Positions for the Past Five Years
William Gallacher[3][4] Alberta, Canada	Chairman and a Director	April 21, 2004	5,940,206/10.0%	President and Chief Executive Officer of Avenir Diversified Income Trust, a public income trust; Owner and Managing Director of Avenir Capital Corporation; Co-founder of Maxim Power Corp., Highland Energy Ltd., Peak Energy Services and Atlas Energy Ltd. Mr. Gallacher also serves on the board of directors of a number of publicly listed and private companies.
James Burns Alberta, Canada	President, Chief Executive Officer and a Director	October 14, 2008	27,200/0.04%	President and Chief Executive Officer of the Company since October, 2008, Prior thereto, Chief Operating Officer of the Company from May, 2008. Prior thereto, President and Chief Executive Officer of Essential Energy Services Trust. From January 1, 2005 to May 31, 2006, Chief Operating Officer, Energy of Avenir Diversified Income Trust. From February 1, 2001 to January 1, 2005. President of two successful emerging oil and gas companies and Executive Vice-President of the Inuvialuit Petroleum Corp., a private oil and gas company.
Gary Dundas[2][5] Alberta, Canada	Director	April 21, 2004	2,581,992/4.36%	Vice-President, Finance, Chief Financial Officer and co-founder of Avenir Diversified Income Trust. Prior to Avenir Diversified Income Trust's inception, in January 2003, Mr. Dundas was an independent consultant from September 2001 to December 2002. Mr. Dundas also serves on the board of directors of a number of publicly listed and private companies.

Name and Place of Residence	Positions with Mahalo [1]	Director Since	Number and Percentage of Common Shares Owned	Principal Occupation and Positions for the Past Five Years
Kevin Wolfe[2][5] Alberta, Canada	Director	July 6, 2005	25,000/0.04%	Independent businessman since September 30, 2008; prior thereto, President and Chief Executive Officer of EnerVest Diversified Management Inc., the Manager of the EnerVest Diversified Income Trust; prior thereto, Senior Vice President of Rockwater Asset Management Inc.; prior thereto, he was the President of Palliser Capital Corp., a privately held financial services advisory firm.
David E. Butler[4] Alberta, Canada	Director	May 31, 2006	173,060/0.29%	President of Passport Petroleums Ltd., a privately owned oil and natural gas company.
William Dawidowski Alberta, Canada	Vice President, Finance and Chief Financial Officer	N/A	31,840/0.05%	Vice President, Finance and Chief Financial Officer of Mahalo. Prior thereto, Vice President, Finance and Chief Financial Officer of Peregrine Energy Ltd.; prior thereto, Vice-President, Finance of Wiser Oil Company of Canada.
David Burton Alberta, Canada	Chief Operating Officer	N/A	769,446/1.30%	Chief Operating Officer of Mahalo. Prior thereto, Vice President, Engineering of Mahalo, prior thereto Manager of Engineering, Ranchgate Energy Inc. and Chief Engineer, Dominion Exploration Canada Ltd.

Notes:
(1) All of the directors of Mahalo have been appointed to hold office until the next annual general meeting of shareholders or until their successor is duly elected or appointed, unless their office is earlier vacated.
(2) Member of the Audit Committee.
(3) Member of the Compensation Committee.
(4) Member of the Health, Safety, Environment and Reserves Committee.
(5) Member of the Corporate Governance Committee

The number of Common Shares beneficially owned, directly or indirectly, by all of the directors and officers of Mahalo is 9,548,744 Common Shares, being approximately 16.1% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

No director is as at the date hereof, or has been, within 10 years of the date hereof, a director, chief executive officer or chief financial officer of any company, including the Company, that while that person was acting in that capacity:

(a) was the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days;

(b) was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the company being the subject of a cease trade or similar order, or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days,

or within a year of that person ceasing to act in that capacity,

(c) became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or comprise with creditors, or had a receiver, receiver manager or trustee appointed to hold its assets; or

(d) has, within the 10 years before the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceeding, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of the director, officer or shareholder.

In addition, no director has had any penalties or sanctions imposed against him or entered into any settlement agreement in respect of any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority, including a settlement agreement with a securities regulatory authority, or any other penalties or sanctions imposed by a court or regulatory body.

Conflicts of Interest

Directors and officers of the Company may, from time to time, be involved with the business and operations of other oil and gas issuers, in which case a conflict may arise. No assurances can be given that opportunities identified by such board members or officers will be provided to the Company. However, directors who have an interest in any proposed transaction upon which the Board of Directors of the Company is voting are required to disclose their interests and refrain from voting on the transaction. See "Risk Factors".

HUMAN RESOURCES

At December 31, 2008 the Company employed 26 full-time employees and 16 consultants.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

As of the date hereof, the Company's subsidiary has approximately US $8.4 million in mechanics liens filed against its oil and gas assets in Oklahoma. In addition the Company is a defendant in a lawsuit for a claim of $387,273.64. The aggregate amount of liens and claims against the Company represents less than 10% of the Company's assets as at December 31, 2009.

Regulatory Actions

During the year ended December 31, 2008, there were (i) no penalties or sanctions imposed against the Company or by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements the Company entered into with a court relating to a securities legislation or with a securities regulatory authority.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as set forth herein, there were no material interests, direct or indirect, of any directors or executive officers of the Company, any shareholder who beneficially owns more than 10% of the outstanding Common Shares or who exercises control or direction over more than 10% of the outstanding Common Shares, or any known associate or affiliate of such

persons, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect the Company.

REGISTRAR AND TRANSFER AGENT

The transfer agent and registrar for the Common Shares is Olympia Trust Company at its principal offices in Calgary, Alberta and Toronto, Ontario.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business or as set forth herein, there were no contracts entered into by Mahalo in the most recently completed financial year which can reasonably be regarded as presently material.

INTERESTS OF EXPERTS

There is no person or corporation who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Company during, or relating to the Company's most recently completed financial year and whose profession of business gives authority to the statement, report or valuation made by the person, or Company, other than Netherland Sewell Associates, Inc., the Company's independent engineering evaluators. To the knowledge of the Company, the experts named above, or if the expert is not an individual, the designated professionals of that expert, did not have any registered or beneficial interests, direct or indirect, in any securities or other property of the Company or of the Company's associates or affiliates at the time they prepared the statement, report or valuation prepared by them, nor did they receive any such interests subsequent to the completion of such statement, report or valuation.

In addition, Ernst & Young LLP, chartered Accountants, is the Company's auditors and as such has prepared an opinion with respect to the Company's consolidated financial statements as at and for the fiscal year ended December 31, 2008. Ernst & Young LLP is independent in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

AUDIT COMMITTEE INFORMATION

Composition of the Audit Committee

The members of the Audit Committee are independent (in accordance with National Instrument 52-110) and are financially literate. The following table sets out the assessment of each of Audit Committee member's independence, financial literacy and relevant educational background and experience supporting such financial literacy. The Board of Directors has not yet found an independent board member to serve as the third committee member on the Audit Committee.

Name and Place of Residence	Independent	Financially Literate	Relevant Education and Experience
Gary Dundas Alberta, Canada	Yes	Yes	Vice-President, Finance, Chief Financial Officer and co-founder of Avenir Diversified Income Trust. Prior to Avenir Diversified Income Trust's inception, in January 2003, Mr. Dundas was an independent consultant from September 2001 to December 2002. Mr. Dundas held the positions of Chief Financial Officer, Vice-President, Finance, General Manager Corporate Development & Marketing and Controller, at Maxx Petroleum Ltd., a publicly traded junior oil and gas company from May 1994 to May 2001.

Name and Place of Residence	Independent	Financially Literate	Relevant Education and Experience
Kevin Wolfe Alberta, Canada	Yes	Yes	Independent Businessman since September 30, 2008; prior thereto, President and Chief Executive Officer of Enervest Diversified Management Inc., the Manager of Enervest Diversified Income Trust; prior thereto, Senior Vice President of Rockwater Asset Management Inc.; prior thereto, he was the President of Palliser Capital Corp., a privately held financial services advisory firm. Mr. Wolfe was the President of Bissett & Associates Investment Management Ltd. from April 1997 to November 2001. In the foregoing roles, Mr. Wolfe has been involved in various aspects of financial planning, budgeting and operations.

Pre-Approval of Policies and Procedures of the Audit Committee

All audit, audit related and non-audit services with our auditors, Ernst & Young LLP, require pre-approval by our Audit Committee.

Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Audit Committee of the Board of Directors is attached hereto as Schedule "C".

Audit Service Fees

The following table sets forth the audit service fees paid by the Company to the Company's external auditors, Ernst & Young LLP, for the years ended December 31, 2007 and December 31, 2008.

Type of Fees	Fiscal 2007	Fiscal 2008	Nature of Services Performed
Audit and audit-related fees	$284,000	$388,000	Audit and review of consolidated financial statements
All other fees	$41,000	$51,000	Services regarding income tax and other matters
Total:	$325,000	$439,000	

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of securities and securities authorized for issuance under equity compensation plans is contained in the Company's Information Circular for the most recent annual meeting of shareholders that involved the election of directors. Additional financial information is also provided in the Company's consolidated financial statements and management's discussion and analysis for the most recently completed financial year, which information is incorporated herein by reference. Documents affecting the rights of security holders, along with other information relating to the Company, may be found on SEDAR at www.sedar.com.

APPENDIX "A"

REPORT OF MAHALO MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE IN ACCORDANCE WITH FORM 51-101F3

Management of Mahalo Energy Ltd. (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is included in this Annual Information Form.

The Board of Directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Board of Directors of the Company has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has approved

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that the reserves are categorized according to the probability of their recovery.

Per: (Signed) "*James Burns*"
President and Chief Executive Officer

Per: (Signed) "*David J. Burton*"
Chief Operating Officer

Per: (Signed) "*Gary Dundas*"
Director

Per: (Signed) "*David Butler*"
Director

Dated March 31, 2009

APPENDIX B

REPORT ON RESERVES DATA BY NETHERLAND SEWELL & ASSOCIATES, INC. IN FORM 51-101F2

To the Board of Directors of Mahalo Energy Ltd. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, estimated using forecast prices and cost.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the period ended December 31, 2008, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Netherland Sewell & Associates, Inc.	Evaluation of the P&NG Reserves of Mahalo Energy Ltd., as of December 31, 2008, dated to March 20, 2009	Canada	nil	3,241	nil	3,241
		United States	nil	127,998	nil	127,998
Total				131,239		131,239

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed, but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation date.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

(Signed) "*G.H. (Scott) Rees III, P.E.*"

Netherland Sewell & Associates, Inc.
Calgary, Alberta
March 31, 2009

SCHEDULE "C"

MAHALO ENERGY LTD.
AUDIT COMMITTEE CHARTER

Introduction

Mahalo Energy Ltd. (the "**Company**") is an Alberta based coalbed methane and unconventional gas exploration and development company founded in 2004. The Board of Directors of the Company (the "**Board**") has the responsibility for the overall stewardship of the conduct of the business of the Company and its subsidiaries and the activities of management of the Company, which is responsible for the day-to-day conduct of the business.

Purpose

The overall purpose of the Audit Committee (the "**Committee**") is to ensure that the Company's management has designed and implemented an effective system of internal financial controls and disclosure controls and procedures, to review and report on the integrity of the consolidated financial statements of the Company, to review the Company's compliance with regulatory and statutory requirements as they relate to financial statements, taxation matters and disclosure of material facts and to review the Company's externally disclosed oil and gas reserves estimates including reviewing the qualifications of, and procedures used by, the independent engineering firm responsible for evaluating the Company's reserves.

Composition, Procedures and Organization

1. The Committee shall consist of at least three members of the Board of Directors (the "**Board**"), all of whom shall be "independent", as that term is defined in Sections 1.4 and 1.5 of Multilateral Instrument 52-110, Audit Committees and who meet the requirements of Section 3.5(1) of National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities.

2. All of the members of the Committee shall be "financially literate" (i.e. able to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of those of the Company and that can be reasonably expected to be raised by the Company's financial statements).

3. The Board shall appoint the members of the Committee. The Board may at any time remove or replace any member of the Committee and may fill any vacancy in the Committee.

4. Unless the Board shall have appointed a chair of the Committee, the members of the Committee shall elect a chair from among their members.

5. The Corporate Secretary of the Company shall be the secretary of the Committee, unless otherwise determined by the Committee.

6. The quorum for meetings shall be a majority of the members of the Committee, present in person or by telephone or other telecommunication device that permits all persons participating in the meeting to speak and to hear each other.

7. The Committee shall have access to such officers and employees of the Company and to the Company's external auditors, and to such information respecting the Company, as it considers necessary or advisable in order to perform its duties and responsibilities.

8. Meetings of the Committee shall be conducted as follows:

    (a) the Committee shall meet at least four times annually at such times and at such locations as may be requested by the chair of the Committee. The external auditors or any member of the Committee may request a meeting of the Committee;

(b) the external auditors shall receive notice of and have the right to attend all meetings of the Committee; and

(c) the following management representatives shall be invited to attend all meetings, except executive sessions and private sessions with the external auditors:

President and Chief Executive Officer
Chief Financial Officer
Controller

(d) other management representatives shall be invited to attend as necessary.

9. The external auditors shall report directly to the Committee and the external auditors and internal auditors (if any) shall have a direct line of communication to the Committee through its chair and may bypass management if deemed necessary. The Committee, through its chair, may contact directly any employee of the Company as it deems necessary, and any employee may bring before the Committee any matter involving questionable, illegal or improper financial practices or transactions.

10. The Committee may retain, at the Company's expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties and may set and pay the compensation for any advisor engaged. The Committee will notify the Chairman of the Corporate Governance Committee whenever independent consultants are engaged.

Roles and Responsibilities

1. The overall duties and responsibilities of the Committee shall be as follows:

(a) to assist the Board in the discharge of its responsibilities relating to the Company's accounting principles, reporting practices and internal controls and its approval of the Company's annual and quarterly consolidated financial statements and management's discussion and analysis;

(b) to establish and maintain a direct line of communication with the Company's internal (if any) and external auditors and assess their performance;

(c) to assist the Board in the discharge of its responsibilities relating to oversight of the Company's internal, financial and disclosure controls and procedures;

(d) to periodically review the audit and non-audit services pre-approval policy and recommend to the Board any changes which the Committee deems appropriate;

(e) to periodically consider whether there is a need to outsource internal audit functions or create an internal audit department;

(f) to assist the Board in the discharge of its responsibilities relating to the evaluation and disclosure of its oil and gas reserves and oil and gas activities and the approval and filing of all necessary statements and reports related thereto;

(g) to receive and review complaints received pursuant to the Company's Whistleblower Policy and oversee and provide direction on the investigation and resolution of such concerns and to periodically review the said policy and recommend to the Board changes which the Committee may deem appropriate;

(h) to report regularly to the Board on the fulfilment of its duties and responsibilities;

(i) to identify and monitor the management of the principal risks that could impact the financial reporting of the Company; and

(j) review and approve the Company's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Company.

2. The duties and responsibilities of the Committee as they relate to the external auditors shall be as follows:

(a) to be directly responsible for overseeing the work of the external auditors engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Company, including the resolution of disagreements between management and the external auditors regarding financial reporting;

(b) to recommend to the Board a firm of external auditors to be nominated for appointment by the shareholders of the Company, and to monitor and verify the independence of such external auditors;

(c) to review and approve the fee, scope and timing of the audit and other audit related and non-audit services rendered by the external auditors;

(d) review the audit plan of the external auditors prior to the commencement of the audit;

(e) to review with the external auditors, upon completion of their audit:

(i) contents of their report;

(ii) scope and quality of the audit work performed;

(iii) adequacy of the Company's financial and auditing personnel;

(iv) co-operation received from the Company's personnel during the audit;

(v) internal resources used;

(vi) significant transactions outside of the normal business of the Company;

(vii) significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles or management systems; and

(viii) the non-audit services provided by the external auditors, as pre-approved pursuant to the audit and non-audit services pre-approval policy;

(f) to discuss with the external auditors the quality and not just the acceptability of the Company's accounting principles;

(g) to review any unresolved issues between management and the external auditors that could affect the financial reporting or internal controls of the Company; and

(h) to implement structures and procedures to ensure that the Committee meets the external auditors on a regular basis in the absence of management.

3. The duties and responsibilities of the Committee as they relate to the internal control procedures of the Company are to:

(a) review the appropriateness and effectiveness of the Company's policies and business practices which impact on the financial integrity of the Company, including those relating to insurance, accounting, information services and systems and financial controls, management reporting and risk management;

(b) review compliance under the Company's Code of Business Conduct Policy with those matters addressed in the policy which affect the financial integrity of the Company and to periodically review this policy and recommend to the Board changes which the Committee may deem appropriate; and

(c) periodically review the Company's financial and auditing procedures and the extent to which recommendations made by the internal accounting staff or by the external auditors have been implemented.

4. The Committee is also charged with the responsibility to:

(a) review and recommend to the Board for its approval, the Company's annual financial statements, management's discussion and analysis, annual information form and annual earnings press releases before the Company publicly discloses this information;

(b) review and approve the Company's interim financial statements, interim management's discussion and analysis including the impact of unusual items and changes in accounting principles and estimates and report to the Board with respect thereto and interim earnings press releases before the Company publicly discloses this information;

(c) review and approve the financial sections of:

(i) the annual report to shareholders;

(ii) the annual information form;

(iii) prospectuses;

(iv) other public reports requiring approval by the Board; and

(v) press releases related thereto,

and report to the Board with respect thereto;

(d) review regulatory filings and decisions as they relate to the Company's consolidated financial statements;

(e) review the appropriateness of the policies and procedures used in the preparation of the Company's consolidated financial statements and other required disclosure documents, and consider recommendations for any material change to such policies;

(f) review and report on the integrity of the Company's consolidated financial statements;

(g) review the minutes of any audit committee meeting of any subsidiary of the Company;

(h) review with management, the external auditors and, if necessary, with legal counsel, any litigation, claim or other contingency, including tax assessments that could have a material effect upon the financial position or operating results of the Company and the manner in which such matters have been disclosed in the consolidated financial statements;

(i) review the Company's compliance with regulatory and statutory requirements as they relate to financial statements, tax matters and disclosure of material facts; and

(j) develop a calendar of activities to be undertaken by the Committee for each ensuing year related to the Committee's duties and responsibilities as set forth in this Charter and to submit the calendar in the appropriate format to the Board of Directors within a reasonable period of time following each annual general meeting of shareholders.

Annual Review and Assessment

The Committee shall conduct an annual review and assessment of its performance, including compliance with this Charter and its role, duties and responsibilities, and submit such report to the Board of Directors.