Hemisphere energy corporation

ANNUAL INFORMATION FORM

For the year ended December 31, 2012

April 5, 2013

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APPENDICES

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrels	Mcf	thousand cubic feet
bbl/d	barrels per day	Mcf/d	thousand cubic feet per day
bopd	barrels of oil per day	MMcf	million cubic feet
boe	barrels of oil equivalent	MMbtu	million British thermal units
boe/d	boe per day	Bcf	billion cubic feet
Mboe	thousand barrels of oil equivalent	GJ	gigajoule
Mbbl	thousand barrels		
NGL	natural gas liquids		

Other	
M$	thousands of dollars
$/boe	dollar per barrel of oil equivalent
ha	hectare
3D	three dimensional
API	American Petroleum Institute
°API	specific gravity of crude oil measured on the API gravity scale
AECO	Alberta Energy Company, the benchmark natural gas price determined at the AECO 'C' hub in southeast Alberta
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
W.I.	working interest

BARREL OF OIL EQUIVALENCY

Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

CONVERSIONS

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbl	cubic metres	0.159
cubic metres	bbl	6.289
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
MMbtu	gigajoules	1.0526

CURRENCY

All amounts are expressed in Canadian dollars unless otherwise stated.

FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein and the documents incorporated by reference herein including, without limitation, financial and business prospects and financial outlook, reserve and production estimates, drilling plans, activities to be undertaken in various areas, timing of drilling, recompletion and tie-in of wells, tax horizon, timing of development of undeveloped reserves, commodity prices and foreign exchange rates, planned capital expenditures, the timing thereof and the method of funding may be forward-looking statements which reflect management's expectations regarding future plans and intentions, growth, results of operations, performance and business prospects and opportunities. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, changes in environmental or other legislation, reliance on key management personnel, changes in general economic and business conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "*Risk Factors*" and elsewhere herein. The recovery and reserve estimates of Hemisphere's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. In addition, forward-looking statements may include statements attributable to third party industry sources. There can be no assurances that the plans, intentions or expectations upon which such forward-looking statements are based will occur.

Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Hemisphere believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because Hemisphere can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Hemisphere operates; the timely receipt of any required regulatory approvals; the ability of Hemisphere to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results, the ability of the operator of the projects which Hemisphere has an interest in to operate the project in a safe, efficient and effective manner; the ability of Hemisphere to obtain financing on acceptable terms; well production rates and decline rates; the ability to replace and expand the oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Hemisphere to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Hemisphere operates; and the ability of Hemisphere to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhausted. Additional information on these and other factors that could affect Hemisphere's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through System for Electronic Document Analysis and Retrieval ("SEDAR") at www.sedar.com and Hemisphere's website at www.hemisphereenergy.ca. Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot give assurance that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and Hemisphere assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward-looking statements and other information contained herein or the documents incorporated by reference herein concerning the oil and gas industry and Hemisphere's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which Hemisphere believes to be reasonable. However, this data is inherently imprecise. While Hemisphere is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking statements included in this Annual Information Form ("AIF") are made as of the date of this AIF and the Company undertakes no obligation to publicly update such forward-looking statements to reflect new information, subsequent events or otherwise unless required by applicable securities laws.

DESCRIPTION OF THE COMPANY

General

Hemisphere Energy Corporation ("Hemisphere" or the "Company") was incorporated under the laws of the Province of British Columbia on March 6, 1978. The Company does not have any subsidiaries. Its head office is located at Suite 570, 789 West Pender Street, Vancouver, British Columbia V6C 1H2 and its registered office is located at 2900-550 Burrard Street, Vancouver, British Columbia V6C 0A3.

Hemisphere is a junior exploration and production, oil and gas company focused on developing core areas that provide low to medium risk drilling opportunities to increase production, reserves and cash flow. The Company has operations in the Jenner area in southeast Alberta and the Trutch area in northeast British Columbia. Hemisphere’s continued growth plan is through drilling existing prospects and executing strategic acquisitions and farm-ins. Hemisphere trades on the TSX Venture Exchange under the symbol "HME".

History of the Company

Fiscal year ended February 28, 2011

On July 26, 2010, Hemisphere closed an acquisition in Trutch, British Columbia. The acquisition included working interests ranging from 9% to 30% in various assets throughout the property for a total cost of $300,000 in cash and an additional $50,000 through the issuance of 214,225 common shares.

On August 25, 2010, the Company closed a non-brokered private placement resulting in the issuance of 5.0 million common shares for gross proceeds of $1.0 million.

On November 18, 2010, Hemisphere entered into a farm-in agreement to earn lands in Jenner, Alberta which gave the Company the opportunity to farm-in on five net sections of land with petroleum and natural gas rights to the base of the Mannville formation.

On December 21, 2010, the Company closed a non-brokered private placement resulting in the issuance of 2.5 million common shares on a flow-through basis for gross proceeds of $750,000.

Approaching fiscal year-end, Hemisphere closed an acquisition on February, 28, 2011 in Wainwright, Alberta which included 435 net acres of land and 68.75% working interest in one natural gas well producing approximately 175 Mcf/d gross (120 Mcf/d net) for $15,000.

Fiscal year ended February 29, 2012

On March 25, 2011, the Company closed an acquisition in Jenner which included approximately 25 bopd, associated facilities and infrastructure, 100% working interest in 2,600 acres of land, and a 3D seismic survey that covered a portion of the acquired lands for a total cost of $1.1 million.

On May 5, 2011, Hemisphere closed a non-brokered private placement resulting in the issuance of 2.6 million common shares for gross proceeds of $1.0 million and 1.4 million common shares on a flow-through basis for gross proceeds of $621,000.

On July 21, 2011, the Company announced initial production results from the first horizontal well of its drilling program targeting oil in the Glauconitic formation in Jenner. During the first five days of production, the stabilized production rate for the last 72 hours was 230 bopd.

On November 10, 2011, Hemisphere closed a non-brokered private placement resulting in the issuance of 2.2 million flow-through shares for gross proceeds of $1.4 million. The Company also closed an acquisition in Trutch increasing its production and working interests ranging 30% to 100% for $250,000 cash and 100,000 common shares valued at $0.35 each.

On November 15, 2011, the Company announced it completed and equipped the second horizontal oil well of its drilling program targeting the Glauconitic formation in Jenner. The well tested an average 156 bopd over a 72 hour period.

On January 10, 2012, Hemisphere announced it completed and equipped the third horizontal well targeting oil in the Glauconitic formation on its Jenner property and provided initial production results. During twelve days of production, the average production rate over the last 72 hours was approximately 207 bopd.

Also on January 10, 2012, Hemisphere entered a farm-in agreement to earn land in Jenner whereby the Company committed to drilling one horizontal well with the option of drilling a second well to earn additional land.

On January 27, 2012, Hemisphere closed a strategic acquisition in Jenner producing approximately 98 bopd, additional oil processing facilities, 8.5 net sections (5,380 acres) of land and 3D seismic coverage for a total cost of $6.0 million. In January, the Company closed this acquisition in conjunction with a brokered private placement resulting in the issuance of 12.3 million common shares for gross proceeds of $8.6 million.

Ten months ended December 31, 2012

On June 14, 2012, the Company entered into a seismic option and farm-in agreement in the Jenner area which included initial obligations to acquire 3D seismic data and the option to drill a test well with the potential to acquire additional 3D seismic and drill additional wells to earn a maximum of 6.5 sections.

On November 16, 2012, the Company filed a Notice of Change in Year-End under NI 51-102 *Continuous Disclosure Obligations* ("NI 51-102") changing the Company's fiscal year-end from February 28 to December 31 to better align financial reporting with the calendar year and industry peers. The transition year from March 1, 2012 to December 31, 2012 included reporting the nine months ended November 30, 2012, followed by the ten months ended December 31, 2012.

On December 20, 2012, the Company closed the first tranche of a non-brokered private placement resulting in the issuance of 1.8 million common shares for gross proceeds of $1.2 million.

During the year, Hemisphere successfully drilled eight oil wells (7 horizontal and 1 vertical). The Company also expanded its landholdings through Crown land sales acquiring 2.25 sections (1,440 acres) in southeast Alberta. Existing facilities at Jenner were upgraded adding a heated free-water-knockout separator for greater fluid handling capacity and reduction of operating costs.

Recent Developments

On January 9, 2013, Hemisphere further expanded its land base in Jenner and acquired 7.75 sections (4,803 acres) through a Crown land sale.

On January 25, 2013, the Company closed the second and final tranche of a non-brokered private placement from the December 2012 offering, resulting in the issuance of 86,900 million common shares for gross proceeds of $56,485.

Significant Acquisitions

Hemisphere closed a property acquisition in Jenner, Alberta on January 27, 2012 which was considered a significant acquisition under Part 8 of NI 51-102. The Company filed a Form 51-102F4 - *Business Acquisition Report* ("BAR") with respect to this transaction on SEDAR on June 26, 2012. The Company is currently in the process of providing further clarification on this BAR by preparing the applicable operating statements as requested by the BC Securities Commission on April 5, 2013. The Company plans to file an amended BAR, including the required operating statements no later than May 31, 2013.

Human Resources

As at December 31, 2012, Hemisphere had six full-time head office employees and one full-time field employee. Additionally, the Company had five part-time consultants.

Risk Factors

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Company's other public filings before making an investment decision. The risks set out below are not an exhaustive list, nor should be taken as a complete summary or description of all the risks associated with the business of the Company and the oil and natural gas business generally.

Exploration, Development and Production Risks

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 the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Company may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Company'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 the Company will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Company 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 the Company.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also 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. 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.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Company 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. In accordance with industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Although the Company maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Company could incur significant costs. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Global Economic Downturn

In the event of a continued general economic downturn or a recession, there can be no assurance that the business, financial condition and results of operations of the Company would not be materially adversely affected.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Company is and will continue to be affected by numerous factors beyond its control. The Company's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Company may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines 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.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Company'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 the Company's reserves. The Company might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Company's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Company. These factors include economic conditions, in the United States and Canada, the actions of the Organization of the Petroleum Exporting Countries ("OPEC"), governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Company's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Company may, in part, be determined by the Company's borrowing base. A sustained material decline in prices from historical average prices could reduce the Company's borrowing base, therefore reducing the bank credit available to the Company which could require that a portion, or all, of any outstanding bank debt of the Company be repaid.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Company makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the Company can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Company, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Company.

Operational Dependence

Other companies operate some of the assets in which the Company has an interest. As a result, the Company has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Company's financial performance. The Company's return on assets operated by others therefore depends upon a number of factors that may be outside of the Company'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

The Company 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. The Company'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 capacity;
- the availability of storage 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;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Company 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.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (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 the Company and may delay exploration and development activities.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, the Company's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Company's oil and gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Company intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Company's reserves since that date.

Competition

The petroleum industry is competitive in all its phases. The Company competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Company's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Company. The Company's ability to increase its 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 and storage. Competition may also be presented by alternate fuel sources.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) 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 exploration and production practices and activities, 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 natural gas and crude oil and increase the Company's costs, any of which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In order to conduct oil and gas operations, the Company will require licenses and permits from various governmental authorities. There can be no assurance that the Company will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

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, the suspension or revocation of necessary licenses and permits, and civil liability for pollution damage. 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 the Company to incur costs to remedy such discharge. Although the Company believes that it will be 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 have a material adverse effect on the Company's business, financial condition, results of operations and prospects. There has been much public debate with respect to Canada's and Provincial Governments' strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases 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 the evolving legislative requirements, it is not possible to predict the impact on the Company and its operations and financial condition. See "*Industry Conditions – Environmental and Climate Change Regulation*".

Substantial Capital Requirements

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Company's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Company to additional access to capital risk. 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 the Company. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Company 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 the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Company's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Company's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Company'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 terms acceptable to the Company. Continued uncertainty in domestic and international credit markets could materially affect the Company's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Company's ability to execute its business strategy and on its business, financial condition, results of operations and prospects**.**

Changes to the Royalty Regime

There can be no assurance that the governments of Alberta, British Columbia or Canada will not adopt a new royalty regime or modify the methodology of royalty calculations which would increase the royalties paid by the Company. An increase of royalty rates would reduce the Company's earnings and make certain of the Company's projects uneconomic. See "*Industry Conditions - Provincial Royalties and Incentives*".

Issuance of Debt

From time to time the Company 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 the Company's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Company may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Company's articles nor its by-laws limit the amount of indebtedness that the Company may incur. The level of the Company's indebtedness from time to time, could impair the Company's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian / United States dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Company's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Company's reserves as determined by independent evaluators.

To the extent that the Company engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Company may contract.

An increase in interest rates could result in a significant increase in the amount the Company pays to service debt, which could negatively impact the market price of the common shares of the Company.

Hedging

From time to time the Company 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, the Company will not benefit from such increases and the Company may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Company 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, the Company will not benefit from the fluctuating exchange rate.

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 the Company's claim which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company’s actual interest in properties may, therefore, vary from its records.

Insurance

The Company's involvement in the exploration for and development of oil and natural gas properties may result in the Company becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Company maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Company may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that the Company is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Company is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle-East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Company's net production revenue.

In addition, the Company's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Company's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company will not have insurance to protect against the risk from terrorism.

Dilution

The Company may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Company which may be dilutive.

Management of Growth

The Company may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Company to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Company to deal with this growth may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

The Company's properties are held in the form of licences and leases and working interests in licences and leases. If the Company or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Company's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Company.

Third Party Credit Risk

The Company may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Company, such failures may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until the Company finds a suitable alternative partner.

Reliance on Key Personnel

The Company's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company does not have any key person insurance in effect for the Company. The contributions of the existing management team to the immediate and near term operations of the Company are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Company.

Forward-Looking Information May Prove Inaccurate

Investors are cautioned not to place undue reliance on forward-looking information. By its nature forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Income Taxes

The Company files all required income tax returns and believe that we are in full compliance with the provisions of the *Income Tax Act* (Canada) and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Company, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Company. Furthermore, tax authorities having jurisdiction over Hemisphere and may disagree with how the Company calculates its income for tax purposes or could change administrative practices to Hemisphere's detriment.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Company is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Dividends

The Company does not currently pay any dividends on its outstanding common shares. Payment of dividends in the future will be dependent on, among other things, the Company's cash flow, results of operations and financial condition, the need for funds to finance ongoing operations and other considerations, as the Board of Directors of the Company considers relevant.

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 British Columbia, 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 - 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 m^3/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 governments of Alberta and British Columbia also regulate the volume of natural gas that may be removed from those provinces 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 oil and 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. These factors may limit the ability to produce and market such production, and therefore western Canadian production may receive discounted pricing. Current pipeline construction projects before various regulatory bodies, if approved, are expected to alleviate this risk.

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

Other than relatively small amounts held by private parties and First Nations, natural resources in Canada are owned by the Provinces; as such, royalties fall primarily under provincial jurisdiction. Provincial royalty regimes are 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.

Provincial 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. Generally, royalty holidays and reductions reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and increase the net income and funds from operations of such producers.

Alberta

In Alberta, producers of oil and natural gas from Crown lands are required to pay annual rental payments, currently at a rate of $3.50 per ha, and make monthly royalty payments in respect of oil and natural gas produced.

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. On March 11, 2010, the Government of Alberta announced further changes to Alberta's royalty system including a decrease in the maximum royalty rates for conventional oil and natural gas production effective for the January 2011 production month. Alberta royalties in effect after December 31, 2010 are known as the "Alberta Royalty Framework" ("ARF").

Under the ARF, royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly using separate variables to account for production rates and market prices. Royalty rates for conventional oil under the NRF ranged from 0-50%, and rate caps were set at $120 per barrel. Effective January 1, 2011, the maximum royalty payable under the ARF was reduced to 40%. The royalty curve for conventional oil announced on May 27, 2010 amended the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than \$535/m^3 compared to the previous royalty curve.

Royalty rates for natural gas under the NRF ranged from 5-50%, and rate caps were set at $16.59/GJ. Effective January 1, 2011, the maximum royalty payable under the ARF was reduced to 36%. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than $5.25/GJ compared to the previous royalty curve.

The Alberta government also levies royalties on volumes of propane, butane, pentanes plus and sulphur produced from Crown lands.

On April 10, 2008, the Government of Alberta introduced two royalty programs to be implemented along with the NRF to encourage the development of deep oil and gas reserves: (a) a five-year oil program for exploration wells over 2,000 meters that provides royalty adjustments to offset higher drilling costs (these oil wells qualify for up to $1 million, or 12 months, of royalty offsets, whichever comes first); and (b) a five-year natural gas deep drilling program for wells deeper than 2,500 meters (these natural gas wells receive a sliding scale royalty credit according to depth, of up to $3,750 per meter for exploratory wells and $3,000 per meter for development wells). On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of $875,000 for wells exceeding 4,000 metres that are spudded subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes. The natural gas deep drilling program has since been extended indefinitely and will be reviewed by the Government of Alberta on a regular basis.

In response to the drop in commodity prices, 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 meters) received a one-time option, on a well by well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers were only able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that had already elected to adopt such rates as of that date were permitted to switch to Alberta's conventional royalty structure up until February 15, 2011. On January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the ARF. Production from wells operating under the transitional royalty rates will not be subject to the royalty curves for conventional oil and natural gas.

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity 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 was initially made available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, subject to certain maximum amounts 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 applied to wells beginning production of conventional oil and natural gas between April 1, 2009 and March 31, 2010 and provided 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. In June, 2009, the Government of Alberta announced the extension of these two incentives for one year to March 31, 2011. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5% for the first 12 months of production would be made permanent, with the same volume limitations. The New Well Royalty Regulation, pertaining to the same, was approved by an Order-in-Council on March 17, 2011.

In addition to the foregoing, on May 27, 2010, the Government of Alberta announced a number of new initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "Emerging Resource and Technologies Initiative"). Specifically:

- Coalbed methane wells receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;
- Shale gas wells receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;
- Horizontal gas wells receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and
- Horizontal oil wells and horizontal non-project oil sands wells receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

The Emerging Resource and Technologies Initiative will be reviewed in 2014, and the Government of Alberta has committed to providing industry with three years notice at that time if it decides to discontinue the program.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold production taxes. The level of the freehold production tax is based on the volume of monthly production and a specified rate of tax for both oil and gas.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments with respect to the Crown leases (currently at a rate of $7.50 per ha), and make monthly payments in respect of royalties and freehold production taxes due in respect of oil and gas produced from Crown and freehold lands.
The amount payable as a royalty in respect of oil depends on the type of oil, the value of the oil, the quantity of oil produced in a month, and the vintage of the oil. Generally, the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 ("old oil"), between October 31, 1975, and June 1, 1998 ("new oil"), or after June 1, 1998 ("third-tier oil"). The royalty rates are calculated in three stages, which take into account the vintage of the oil, if the oil produced has already been sold and any royalty exempt value applicable. Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 produced, whichever comes first; and the royalties for third-tier oil are the lowest reflecting the higher costs of exploration and extraction that the producers would incur.

The royalty payable on natural gas produced from Crown lands is determined by a sliding scale based on a reference price, which is the greater of the average net price obtained by the producer, and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas as an incentive for the production and marketing of natural gas which might otherwise have been flared.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. For natural gas, the freehold production tax is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas.

The Government of British Columbia has several royalty credit and royalty reduction programs targeted to increase the competitiveness of low productivity wells, including the following:

- Summer Royalty Credit Program providing a royalty credit of 10% of drilling and completion costs up to $100,000 for wells spudded between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;
- Deep Royalty Credit Program providing royalty credits for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 2,300 metres spudded between December 1, 2003 and September 1, 2009 or for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 1,900 metres spudded after August 31, 2009;
- Deep Re-Entry Royalty Credit Program providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres and a re-entry date subsequent to December 1, 2003;
- Deep Discovery Royalty Credit Program providing the lesser of a 3-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation with a spud date after November 30, 2003;
- Coalbed Gas Royalty Reduction and Credit Program providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m^3 as well as a royalty credit for coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land;
- Marginal Royalty Reduction Program providing royalty reductions for low productivity natural gas wells with average monthly production under 25,000 m^3 during the first 12 production months and average daily production less than 23 m^3 for every metre of marginal well depth;

- Ultra-Marginal Royalty Reduction Program providing additional royalty reductions for low productivity shallow natural gas wells with a true vertical depth ("TVD") of less than 2,500 metres in the case of vertical wells, and a TVD of less than 2,300 metres in the case of a horizontal well, average monthly production under 60,000 m^3 during the first 12 production months and average daily production less than 11 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every metre of ultra-marginal well depth; and
- Net Profit Royalty Reduction Program providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 of production, whichever comes first.

In August 2012, the Government of British Columbia announced that it is bringing in a nominal 2% royalty on both oil and natural gas on the revenue for the first year of production for wells drilled from September 2012 through to June 2013.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program (the "Infrastructure Royalty Credit Program") which provides royalty credits for up to 50% of the lesser of the estimated completion cost and the completion cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. In 2009, 2010 and 2011, the Government of British Columbia allocated $120 million in royalty credits for oil and gas companies under the Infrastructure Royalty Credit Program. The Government of British Columbia awarded another $120 million in royalty credits under the Infrastructure Royalty Credit Program in 2012.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. Natural gas wells spudded within the 10-month period from September 1, 2009 to June 30, 2010 and brought on production by December 31, 2010 qualify for a 2% royalty rate for the first 12 months of production, beginning from the first month of production for the well (the "Royalty Relief Program"). British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres. Wells spudded between September 1, 2009 and June 30, 2010 may qualify for both the Royalty Relief Program and the Deep Royalty Credit Program but will only receive the benefits of one program at a time.

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, 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.

Each of the Provinces of Alberta and British Columbia has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. On March 29, 2007, British Columbia's policy of deep rights reversion was expanded for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

In Alberta, the NRF includes a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. 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. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009. The order in which these agreements will receive reversion notices will depend on their vintage and location, and Alberta Energy had anticipated that the receipt of reversion notices for older leases and licenses would commence in April 2011. However, on April 14, 2011, Alberta Energy announced it is deferring serving shallow rights reversion notices. This decision was to be revisited in spring 2012 and the formal response from Alberta Energy is expected to be communicated to industry in spring 2013.

Environmental and Climate Change Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, which may be amended from time to time. Such legislation provides for restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and 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, the suspension or revocation of necessary licenses and permits, and civil liability for pollution damage.

Alberta

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 environmental standards, reporting and monitoring obligations, and penalties for non-compliance.

In December, 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "ALUF"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

The Alberta Land Stewardship Act (the "ALSA") was proclaimed in force in Alberta on October 1, 2009 and provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA will be deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, leases, licenses, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Alberta government approved the Lower Athabasca Regional Plan (the "LARP"), which came into effect on September 1, 2012. The LARP is the first regional plan to be developed under the ALSA. The LARP covers the northeast corner of Alberta and the entirety of the Athabasca oil sands region. Among other provisions, the LARP requires a cumulative effects management approach which involves managing air, water and biodiversity through management frameworks that set environmental limits and triggers. The LARP also establishes several new conservation areas where new resource developments will generally be prohibited.

Alberta enacted the Climate Change and Emissions Management Act (the "CCEMA") on December 4, 2003, amending it through the Climate Change and Emissions Management Amendment Act, which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020. Alberta facilities emitting more than 100,000 tonnes of carbon dioxide equivalent a year are subject to compliance with the CCEMA.

As at year-end 2012, Hemisphere did not have an interest in any facilities in Alberta that emit more than 100,000 tonnes of carbon dioxide equivalent per year.

On December 2, 2010, the Government of Alberta passed the Carbon Capture and Storage Statutes Amendment Act, 2010. It deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

British Columbia

In February, 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is $30 per tonne of carbon dioxide equivalent. BC is currently undertaking a comprehensive review of the carbon tax, and may or may not make changes to its carbon tax regime. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

On April 3, 2008, British Columbia introduced the Greenhouse Gas Reduction (Cap and Trade) Act (the "Cap and Trade Act") which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on greenhouse gas emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia facilities emitting over 10,000 tonnes of carbon dioxide equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of carbon dioxide equivalents per year are required to have their emissions reports verified by a third party. Regulations pertaining to proposed offsets and emissions trading remain in development.

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("Kyoto Protocol"), which requires a reduction in greenhouse gas ("GHG") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 although on December 12, 2011 Canada formally withdrew from the Kyoto Protocol.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "Action Plan") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas

Emissions" was released on March 10, 2008 (the "Updated Action Plan"). The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later.

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 gross domestic product 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. A draft of three Program Rules and Guidance documents detailing eligibility requirements and the application processes are expected to be published in the fall of 2009. Canada's offset system will be administered under the Canadian Environmental Protection Act, 1999.

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.

Although draft regulations for the implementation of the Updated Action Plan were intended to become binding on January 1, 2010, only draft regulations pertaining to carbon dioxide emissions from coal-fired generation of electricity have been proposed to date. Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent, if any; the proposals contained in the Updated Action Plan will be implemented.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting legislative 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.

STATEMENT OF RESERVES AND OTHER OIL AND NATURAL GAS INFORMATION

In accordance with National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("NI-51-101") and Canadian Oil and Gas Evaluation Handbook reserve definitions, Sproule Associates Limited ("Sproule") prepared a report for the Company dated March 19, 2013 with the effective date December 31, 2012 (the "Sproule Report"). The Sproule Report evaluated Hemisphere's oil, NGL and natural gas reserves. All properties evaluated are in Canada and specifically in Alberta and British Columbia.

The tables below are a summary of the oil, NGL and natural gas reserves attributable to Hemisphere's properties and the net present values of future net revenue attributable to such reserves as evaluated in the Sproule Report based on forecast price and cost assumptions. The tables summarize the data contained in the Sproule Report and, as a result, may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

The net present values of future net revenue attributable to reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures and well abandonment costs for only those wells assigned reserves by Sproule. It should not be assumed that the undiscounted or discounted net present values of future net revenue attributable to reserves estimated by Sproule represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of oil, NGL and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein.

The Sproule Report is based on certain factual data supplied by the Company and Sproule's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Company to Sproule. Sproule accepted this data as presented and neither title searches nor field inspections were conducted.

Readers should review the definitions and information contained in "*Additional Information Relating to Reserve Data*" below in conjunction with the following tables and notes. The recovery and reserve estimates on Hemisphere's properties described herein are estimates only. The actual reserves on Hemisphere's properties may be greater or less than those calculated. See "*Risk Factors*".

Summary of Oil and Gas Reserves – Forecast Prices and Costs

	Light & Medium Oil		**Heavy Oil**		**Natural Gas**		**Natural Gas Liquids**	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
Proved								
Developed Producing	-	-	471.4	397.7	299	274	7.2	5.2
Developed Non-Producing	-	-	23.0	20.7	108	100	-	-
Undeveloped	-	-	243.0	214.5	-	-	-	-
Total Proved	**-**	**-**	**737.4**	**632.9**	**406**	**375**	**7.2**	**5.2**
Probable	-	-	392.8	325.5	317	258	6.9	4.9
Total Proved Plus Probable	**-**	**-**	**1,130.2**	**958.4**	**724**	**633**	**14.2**	**10.1**

Summary of Net Present Values of Future Net Revenue – Forecast Prices and Costs

	Before Income Taxes and Discounted at				
(M$)	0%	5%	10%	15%	20%
Proved					
Developed Producing	17,705	15,661	14,094	12,862	11,871
Developed Non-Producing	567	539	513	489	468
Undeveloped	5,057	4,111	3,363	2,761	2,271
Total Proved	**23,329**	**20,312**	**17,970**	**16,112**	**14,609**
Probable	14,562	10,961	8,556	6,878	5,662
Total Proved Plus Probable	**37,891**	**31,272**	**26,526**	**22,991**	**20,270**

	After Income Taxes and Discounted at				
(M$)	0%	5%	10%	15%	20%
Proved					
Developed Producing	17,566	15,554	14,010	12,795	11,817
Developed Non-Producing	423	418	411	402	393
Undeveloped	3,723	2,924	2,298	1,798	1,395
Total Proved	**21,712**	**18,896**	**16,718**	**14,995**	**13,604**
Probable	11,295	8,384	6,461	5,132	4,176
Total Proved Plus Probable	**33,007**	**27,280**	**23,179**	**20,127**	**17,780**

($/boe)	Unit Value **Before** Income Taxes Discounted at 10%/year
Proved	
Developed Producing	31.42
Developed Non-Producing	13.69
Undeveloped	15.68
Total Proved	**25.65**
Probable	22.91
Total Proved Plus Probable	**24.70**

Notes:

NPV of FNR include all resource income:
- *Sale of oil, gas, by-product reserves*
- *Processing third party reserves*
- *Other income*

Income Taxes:
- *Includes all resource income*
- *Apply appropriate income tax calculations*
- *Include prior tax pools*

Unit Values are based on net reserve volumes.

Total Future Net Revenue Undiscounted – Forecast Prices and Costs

(M$)	Revenue	Royalties	Operating Costs	Development Costs	Well Abandon-ment / Other Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Proved	56,681	7,883	18,810	5,798	861	23,329	1,618	21,712
Proved Plus Probable	90,360	13,536	30,087	7,844	1,001	37,891	4,884	33,007

Net Present Value of Future Net Revenue by Production Group – Forecast Prices and Costs

	Future Net Revenue Before Income Taxes Discounted at 10%/Year (M$)	Unit Value Before Income Taxes Discounted at 10%/Year ($/boe)
Proved		
Light and Medium Crude Oil (including solution gas and associated by-products)	-	-
Heavy Oil (including solution gas and associated by-products)	17,699	27.97
Natural Gas (including associated by-products)	271	4.00
Proved Plus Probable		
Light and Medium Crude Oil (including solution gas and associated by-products)	-	-
Heavy Oil (including solution gas and associated by-products)	26,026	27.16
Natural Gas (including associated by-products)	500	4.32

Note:
Unit Values are based on net reserve volumes.

Summary of Pricing and Inflation Rate Assumptions – Forecast Prices and Costs

Sproule employed the following pricing, exchange rate and inflation rate assumptions in estimating the Company's reserves data using forecast prices and costs as of December 31, 2012.

	Oil			Natural Gas	NGL			
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Cromer Medium 29.3° API ($Cdn/bbl)	Natural Gas AECO Gas Prices ($Cdn/MMBtu)	Pentanes Plus FOB Field Gate ($Cdn/bbl)	Butanes FOB Field Gate ($Cdn/bbl)	Inflation Rate (%/Year)	Exchange Rate ($US/$Cdn)
2013	89.63	84.55	77.79	3.31	90.53	63.02	1.5	1.001
2014	89.93	89.84	82.66	3.72	96.19	66.96	1.5	1.001
2015	88.29	88.21	81.15	3.91	94.44	65.74	1.5	1.001
2016	95.52	95.43	88.75	4.70	102.18	71.13	1.5	1.001
2017	96.96	96.87	90.09	5.32	103.71	72.20	1.5	1.001
2018	98.41	98.32	91.44	5.40	105.27	73.28	1.5	1.001
2019	99.89	99.79	92.81	5.49	106.85	74.38	1.5	1.001
2020	101.38	101.29	94.20	5.58	108.45	75.50	1.5	1.001
2021	102.91	102.81	95.61	5.67	110.08	76.63	1.5	1.001
2022	104.45	104.35	97.05	5.76	111.73	77.78	1.5	1.001
2023	106.02	105.92	98.50	5.85	113.40	78.95	1.5	1.001
Thereafter	Escalation Rate of 1.5%							

Note:
Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale.

The weighted average realized sales prices for Hemisphere for the ten months ended December 31, 2012 were $66.76/bbl for oil, $60.87/bbl for NGLs and $2.07 Mcf for natural gas.

Reconciliation of Company Gross Reserves (Before Royalty) by Principal Product Type – Forecast Prices and Costs

The following table sets forth a reconciliation of the Company's gross reserves as at December 31, 2012, derived from the Sproule Report using forecast prices and cost estimates, reconciled to the Company's gross reserves as at February 29, 2012.

	Heavy Oil			Associated and Non-Associated Gas			Natural Gas Liquids			Boe		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
Feb. 29, 2012	337.8	294.1	631.9	480	376	856	9.0	7.4	16.4	426.8	364.1	790.9
Extensions	205.4	79.3	284.7	-	-	-	-	-	-	205.4	79.3	284.7
Infill Drilling	231.2	93.9	325.1	-	-	-	-	-	-	231.2	93.9	325.1
Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	79.4	(75.4)	4.0	13	(31)	(18)	(0.5)	(0.3)	(0.8)	81.2	(80.9)	0.3
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	(0.8)	0.9	0.1	(38)	(27)	(65)	(0.3)	(0.1)	(0.4)	(7.4)	(3.8)	(11.2)
Production	(115.6)	-	(115.6)	(49)	-	(49)	(1.0)	-	(1.0)	(124.8)	-	(124.8)
Dec. 31, 2012*	737.4	392.8	1,130.2	406	318	724	7.2	7.0	14.2	812.4	452.6	1,265.0

Note:
** Year-end reporting date changed to December 31.*

Undeveloped Reserves Vintage by Principal Product Type – Forecast Prices and Costs

	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
	First Attributed Gross (Mbbl)	Booked Gross (Mbbl)	First Attributed Gross (Mbbl)	Booked Gross (Mbbl)	First Attributed Gross (MMcf)	Booked Gross (MMcf)	First Attributed Gross (Mbbl)	Booked Gross (Mbbl)
Proved Undeveloped								
February 28, 2010	-	-	-	-	-	-	-	-
February 28, 2011	-	-	-	-	-	-	-	-
February 29, 2012	-	-	90.0	90.0	-	-	-	-
December 31, 2012*	-	-	157.4	243.0	-	-	-	-
Probable Undeveloped								
February 28, 2010	-	-	-	-	23	23	-	-
February 28, 2011	-	-	75.0	75.0	1	24	-	-
February 29, 2012	-	-	175.0	175.0	3	27	-	-
December 31, 2012*	-	-	69.9	190.3	-	-	-	-

Note:
** Year-end reporting date changed to December 31.*

Proved undeveloped reserves are generally those reserves related to infill wells that have not yet been drilled or wells further away from gathering systems requiring relatively high capital to bring on production. Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. This also includes the probable undeveloped wedge from the proved undeveloped locations.

The Company currently plans to pursue the development of its proven and probable undeveloped reserves within the next two years through ordinary course capital expenditures. However, the Company may choose to delay development depending on a number of circumstances, including the existence of higher priority expenditures and prevailing commodity prices and cash flow.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering or economic data. These estimates may change substantially as additional data from ongoing development activities and production performance become available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. Hemisphere’s reserves are evaluated by Sproule, an independent engineering firm.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can either be positive or negative.

Future Development Costs

The table below sets out the development costs in Canada deducted in the estimation of future net revenue attributable to proved reserves (using forecasted prices and costs only) and proved plus probable reserves (using forecast prices and costs only).

	Forecast Prices and Costs	
	Proved Reserves (M$)	Proved Plus Probable Reserves (M$)
2013	5,798	7,665
2014	-	178
2015	-	-
2016	-	-
2017	-	-
Remaining Years	-	-
Total Undiscounted	**5,798**	**7,843**

Hemisphere typically has available three sources of funding to finance its capital expenditure program: internally generated cash flow from operations, debt financing when appropriate and new equity issues, if available on favourable terms.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

"Associated Gas" means the gas cap overlying a crude oil accumulation in a reservoir.

"Crude oil" or **"oil"** means a mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons, but does not include liquids obtained from the processing of natural gas.

"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 capital 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.

"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.

"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.

"Fair market value" means the price at which a purchaser seeking an economic and commercial return on investment would be willing to buy, and a vendor would be willing to sell, where neither is under compulsion to buy or sell and both are competent and have reasonable knowledge of the facts.

"Future net revenue" means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using constant prices and costs or forecast prices and costs.

"Gas" or **"Natural Gas"** means a mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs, but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds.

"Gross" means:

(a) in relation to the Company's interest in production or reserves, its "Company gross reserves", which are the Company's interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Company;
(b) in relation to wells, the total number of wells in which the Company has an interest; and
(c) in relation to properties, the total area of properties in which the Company has an interest.

"Natural Gas Liquids" means those hydrocarbon components that can be removed from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

"Net" means:

(a) in relation to the Company's interest in production or reserves, its working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalty interest in production or reserves;
(b) in relation to the Company's interest in wells, the 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 a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

"Non-Associated Gas" means an accumulation of natural gas in a reservoir where there is no crude oil.

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

"Probable Reserves" 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.

"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.

"Remaining Recoverable Reserves" means the total remaining recoverable reserves associated with the acreage in which the Company has an interest.

"Solution Gas" means gas dissolved in crude oil.

"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 category (proved, probable, possible) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

OTHER OIL AND GAS INFORMATION

Core Asset

Jenner, Southeast Alberta

The Jenner Property is accessible year-round and is located northeast of Brooks, Alberta. Hemisphere has an average working interest of 98% in approximately 16,146 net acres (6,534 ha). The property, operated by Hemisphere, has multiple zones of potential, existing infrastructure, and low cost drilling and completions. The Company drilled eight wells (7 horizontal and 1 vertical) during the ten months ended December 31, 2012.

Non-Core Assets

Trutch, Northeast British Columbia

The Trutch Property is located approximately 200 kilometres northwest of Fort St. John, British Columbia. Hemisphere has varying working interests from 30% to 100% in approximately 34,788 net acres (14,078 ha). Competitors to the east and south of the Trutch area have been actively exploring and developing the prolific Tommy Lakes Halfway gas field for a number of years. Hemisphere currently has an interest in four producing Halfway formation, liquid-rich, natural gas wells in Trutch and recognizes multi-zone potential in the area. The Company did not drill any wells in this area during 2012.

Sylvan Lake, Central Alberta

The Sylvan Lake Property is located approximately 160 kilometres southwest of Edmonton and 170 kilometres north of Calgary in central Alberta. The property can be accessed year-round. Hemisphere currently has working interests ranging from 15% to 100% in nine producing Edmonton Sand natural gas wells on the property. The Company did not drill any wells in this area during 2012.

Wainwright, Central Alberta

The Wainwright Property is located in an oil-rich area of east central Alberta. Hemisphere recognizes the region's upside potential with year-round access, multiple zones, existing infrastructure and low cost drilling and completions. Hemisphere currently has a working interest of 68.75% in one section of land. The Company did not drill any wells in this area during 2012.

Heathdale, Southeast Alberta

The Heathdale Property is located northeast of Brooks, Alberta and just north of Hemisphere's Jenner Property. The Company entered the area in 2011 and acquired 1.0 section (640 acres) of land.

Oil and Gas Wells

The following table summarizes Hemisphere's interest as at December 31, 2012 in wells that are producing and non-producing:

	Producing Wells				**Non-Producing Wells**			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Jenner, Alberta	14	13.8	1	1.0	20	20.0	-	-
Sylvan Lake, Alberta	-	-	9	1.5	-	-	1	1.0
Wainwright, Alberta	-	-	-	-	-	-	1	0.7
Trutch, British Columbia	-	-	4	1.4	-	-	2	0.8
Total	**14**	**13.8**	**14**	**3.9**	**20**	**20.0**	**4**	**2.5**

Exploration and Drilling Activity

The following table summarizes the gross and net exploration and development wells in which Hemisphere participated during the ten months ended December 31, 2012:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	-	-	8	8.0
Gas	-	-	-	-
Service Wells	-	-	-	-
Stratigraphic Test Wells	-	-	-	-
Dry Wells	-	-	-	-
Total	**-**	**-**	**8**	**8.0**

Production History

The following table summarizes Hemisphere's average daily production for each fiscal quarter during the Company's previous fiscal year ended February 28, 2013 and new fiscal year ended December 31, 2012:

	Three Months Ended			One Month Ended
	May 31, 2012	Aug. 31, 2012	Nov. 30, 2012	Dec. 31, 2012
Oil (bbl/d)	383	335	406	405
Natural gas (Mcf/d)	187	170	132	139
NGL (bbl/d)	4	4	2	2
Total (boe/d)	**418**	**367**	**430**	**430**

Production Estimates

The following table discloses, by product type, the total volume of production estimated by Sproule for the year ended December 31, 2013 in the estimates future net revenue from proved and from probable reserves disclosed under *"Petroleum and Natural Gas Reserves"*.

Proved	**Heavy Oil** (bbl/d)	**Gas** (Mcf/d)	**NGL** (bbl/d)	**Total** (boe/d)
Alberta				
Jenner	493	-	-	493
Sylvan Lake	-	30	-	5
Wainwright	-	59	-	10
Heathdale	-	-	-	-
British Columbia				
Trutch	-	102	-	20
Total	**493**	**191**	**-**	**528**

Proved Plus Probable	Heavy Oil (bbl/d)	Gas (Mcf/d)	NGL (bbl/d)	Total (boe/d)
Alberta				
Jenner	530	-	-	530
Sylvan Lake	-	31	-	5
Wainwright	-	60	-	10
Heathdale	-	-	-	-
British Columbia				
Trutch	46	105	-	21
Total	**576**	**196**	**-**	**566**

Developed and Undeveloped Lands

The following table summarizes, by province, Hemisphere's developed and undeveloped landholdings as at December 31, 2012:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	**Gross**	**Net**
Alberta	6,720	4,314	14,040	14,040	**20,760**	**18,354**
British Columbia	18,755	5,883	18,720	17,184	**39,600**	**34,788**
Total	**25,475**	**10,197**	**32,760**	**31,224**	**60,360**	**53,142**

The Company does not have any landholdings that could expire during the year ended December 31, 2013.

Forward Contracts

As at December 31, 2012, Hemisphere does not have any hedging or marketing arrangements that could materially impact the Company's realized sales price that have not been disclosed as financial instruments in its financial statements.

Additional Information Concerning Abandonment and Reclamation Costs

The Company incurred no abandonment costs and $115,385 in reclamation costs during 2012. Hemisphere estimates well abandonment costs by area. Such costs are included in the Sproule Report as deductions in arriving at future net revenue. The Company expects to incur such costs for 27.6 net wells. The expected total abandonment costs included in the Sproule Report (forecast pricing) under the total proved reserves category is $861,000 undiscounted ($373,000 discounted at 10%), of which no costs (all discounted) are estimated to be incurred in 2013, 2014 and 2015.

As at December 31, 2012, the Company had $151,977 in various reclamation bonds and deposits held by the British Columbia Ministry of Energy, Mines and Natural Gas, and the BC Oil and Gas Commission for its properties. Of this amount, $51,442 was recorded in prepaid expenses for current commitments and $100,535 was recorded in reclamation deposits as non-current assets.

Tax Horizon

The Company was not required to pay income taxes during the year ended December 31, 2012. Taxes payable beyond 2012 will become a function of commodity prices, production volumes and capital expenditures. Based on a strategy of re-investing fully all internally generated cash flow in an exploration and development program and based on the commodity prices used in the Sproule Report, the Company estimates that it will not be required to pay income taxes until 2014.

Costs Incurred

The following table summarizes Hemisphere's property acquisition costs, exploration costs and development costs for the ten months ended December 31, 2012:

	Property Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
Total	**-**	**191,644**	**271,253**	**11,425,501**

DIVIDENDS

Hemisphere has not declared or paid any dividends since its incorporation. The future payments of dividends will depend on the earnings and financial condition of the Company and such other factors as the Board of Directors of the Company consider appropriate. See "*Risk Factors – Dividends*".

SHARE CAPITAL

Common Shares

Hemisphere has an unlimited number of common shares authorized. As of the date of this AIF, there are 54,047,948 common shares outstanding. Holders of Hemisphere's common shares are entitled to notice of meetings and one vote per share at meetings of the Company's Shareholders, to dividends if, as and when declared by the board of directors and upon liquidation, dissolution or winding-up to receive, the Company's remaining property.

Stock Options

The Company has a stock option plan in place and is authorized to grant stock options to officers, directors, employees and consultants whereby the aggregate number of shares reserved for issuance may not exceed 10% of the issued shares at the time of grant and 5% of the issued shares to each optionee. Stock options are non-transferable, and have a maximum term of five years. Stock options terminate not later than 90 days (30 days for investor-related services) upon termination of employment/contract and one year in the case of retirement/death/disability. The grant price may not be less than the last closing price of the Company's shares and not less than $0.10.

As of the date of this AIF, the Company had 4,995,000 stock options outstanding.

Warrants

As of the date of this AIF, the Company had a total of 8,183,445 warrants outstanding comprised of 1,028,841 warrants priced at $0.90 each with a December 20, 2013 expiry, 44,150 warrants priced at $0.90 each with a January 25, 2014 expiry, 862,620 warrants priced at $0.70 each with a January 27, 2014 expiry, and 6,247,834 warrants priced at $0.95 each with a January 27, 2014 expiry.

MARKET FOR SECURITIES

The Common Shares of the Company are listed for trading on the TSX Venture Exchange ("TSX-V") under the symbol "HME".

Common Share Trading

	Price Range High	Low	Average Trading Volume
2012			
January	$0.75	$0.63	43,800
February	$0.70	$0.65	19,700
March	$0.85	$0.68	56,100
April	$0.71	$0.60	26,600
May	$0.65	$0.48	47,300
June	$0.60	$0.46	52,700
July	$0.67	$0.51	45,800
August	$0.60	$0.53	12,900
September	$0.72	$0.60	48,200
October	$0.75	$0.62	76,700
November	$0.75	$0.61	48,600
December	$0.68	$0.53	21,400
2013			
January	$0.61	$0.51	21,400
February	$0.56	$0.40	52,800
March	$0.52	$0.44	32,200
April 1-5	$0.46	$0.44	14,700

DIRECTORS AND OFFICERS

The names, municipalities of residence, any offices held with Hemisphere, the period served as a director and principal occupations of the Company's directors and officers are set out below:

Name and Municipality of Residence	Position with Hemisphere	Director or Officer Since	Principal Occupation During the Past Five Years
Don Simmons, P. Geol.(1) Vancouver, British Columbia	President and Chief Executive Officer Director	February 2008 May 2008	Previously Vice President Exploration of the Company from October 2007. Formerly a Geologist at Sebring Energy, a private oil and gas company, until its sale in 2007.
Charles O'Sullivan, B.Sc.(2)(3) Vancouver, British Columbia	Chairman Director	2000 1978	Geophysicist and Mining Executive. Chairman of the Company since 2000. Chairman of Northern Continental Resources Inc. from 1986 to 2009.
Frank Borowicz, QC, CA (Hon)(3)(4) Surrey, British Columbia	Director	July 2005	Retired partner of Davis LLP. Currently President of Pigasus Consulting Services Ltd. and Governor of the Vancouver Board of Trade since 2005.
Bruce McIntyre, P.Geol.(1)(2)(4) Calgary, Alberta	Director	July 2008	Currently Executive Director of New Zealand Energy Corp. Previously an independent consultant and President of Wexford Energy Ltd., a private company that provides consulting services for the development and operation of producing natural gas companies (private and public) since 2007.

Greg Sadler, P. Eng.(1)(2)(3) Calgary, Alberta	Director	July 2008	Senior Staff Reservoir Engineer with Cenovus Energy Inc. and predecessor companies since 1995.
Gregg Vernon, P. Eng.(1)(4) Bogota, Colombia	Director	August 2006	President of Bochica Oil & Gas Inc. Previously Interim Chief Operating Officer of Petro Magdalena Energy Corp. (formerly Alange Energy Corp.) from January 2011 to its sale in 2012. Previously, the Vice President Business Development of Petro Andina Resources Ltd.
Andrew Arthur, P. Geol. Delta, British Columbia	Vice President, Exploration	July 2012	Consultant for Hemisphere since January 2012. Prior thereto, Technical Lead Oil Business Unit for Enerplus since December 2008 and Vice President, Exploration for PRD Energy Inc. since October 2006.
Ian Duncan, P. Eng. Vancouver, British Columbia	Vice President, Engineering	May 2011	Previously an Engineer at Hemisphere since January 2011. Prior thereto was an Engineer at Solaris MCI and Talimsan Energy Inc.
Dorlyn Evancic, CGA Port Coquitlam, British Columbia	Chief Financial Officer	July 2007	Previously Chief Financial Officer of Northern Continental Resources Inc. from July 2007 to November 2009. Prior thereto, Chief Financial Officer of Guyana Frontier Mining Corp. from December 2010 to November 2011 and Chief Financial Officer of Gemco Minerals Inc. from March 2005 to February 2010.

Notes:

(1) *Member of the Reserves Committee. Greg M. Sadler is the Chairman of the Reserves Committee.*

(2) *Member of the Compensation/Nominating Committee. Charles N. O'Sullivan is Chairman of the Compensation/Nominating Committee.*

(3) *Member of the Corporate Governance Committee. Frank S. Borowicz is Chairman of Corporate Governance Committee.*

(4) *Member of the Audit Committee. Bruce G. McIntyre is Chairman of the Audit Committee.*

Cease Trade Orders

Other than noted below, no current director or officer of Hemisphere has, within the last ten years prior to the date of this AIF, been a director, chief executive officer or chief financial officer of any issuer (including Hemisphere) that:

(a) while the person was acting in the capacity as director, chief executive officer or chief financial officer, was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days; or

(b) was subject to an order that resulted, after the director, executive officer ceased to be a director, chief executive officer or chief financial officer of an issuer, in the issuer being the subject of a cease trade or similar order or an order that denied the relevant issuer access to any exemption under securities legislation, for a period of more than 30 consecutive days, which resulted from an event that occurred while that person was acting as a director, chief executive officer or chief financial officer of the issuer.

Mr. Evancic was a director and officer of Gemco Minerals Inc., which had a cease trade order issued in August 2007 by the British Columbia Securities Commission for revisions required in its technical report pursuant to National

Instrument 43-101 – *Standard of Disclosure for Mineral Projects*. The company fully complied with the British Columbia Securities Commission requirements and revocation of the cease trade was issued in March 2008.

Bankruptcies

No current director, officer, or shareholder holding a significant number of securities to materially affect the control of Hemisphere has, within the last ten years prior to the date of this document, been a director or officer of any company (including Hemisphere) that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement for compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

In addition, no current director, officer or shareholder holding a significant number of securities to materially affect the control of Hemisphere has, within the last ten years prior to the date of this document, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, officer or shareholder.

Penalties or Sanctions

No current director, officer, or shareholder holding a significant number of securities to materially affect the control of Hemisphere has been subject to: (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (ii) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

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 natural gas issuers, in which case a conflict may arise. See "*Risk Factors*".

Circumstances may arise where members of the Company’s Board of Directors serve as directors or officers of corporations which are in competition to Hemisphere’s interests. No assurances can be given that opportunities identified by such Board of Directors members will be provided.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that the Company is or was a party to, or that any of its property is or was subject of, during the last completed fiscal year, nor are any such legal proceedings known to the Company to be contemplated that involves a claim for damages, exclusive of interest and costs, exceeding 10% of the current assets of the Company.

During the fiscal year ended December 31, 2012, 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.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors or executive officers of the Company, any shareholder who beneficially owns, or controls or directs, directly or indirectly, more than 10% of the outstanding common shares of the Company or any known associate or affiliate of such persons in any transactions within the three most recently completed fiscal years of the Company or during the current fiscal year which has materially affected, or would reasonably be expected to materially affect, the Company.

TRANSFER AGENT AND REGISTRAR

The Company's transfer agent and registrar is Computershare Investor Services Inc. located at 3rd floor, 510 Burrard Street, Vancouver, British Columbia V6C 3B9.

INTEREST OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under NI 51-102 by the Company during, or related to, its most recently completed financial year other than Sproule, the Company's independent engineering evaluator and Smythe Ratcliffe LLP, the Company's independent auditors.

Smythe Ratcliffe LLP are the auditors of the Company and have confirmed that they are independent with respect to the Company within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of British Columbia.

None of the designated professionals of Sproule have any registered or beneficial interests, direct or indirect, in any of Hemisphere's securities or other property or of Hemisphere's associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them.

MATERIAL CONTRACTS

Other than the contracts entered into in the ordinary course of business, the Company has not entered any material contracts in the most recently completed fiscal year. Prior to the most recent fiscal year, the Company entered into the following material contracts that are still in effect:

- A Shareholder Rights Plan between Hemisphere and Computershare Investor Services Inc. was executed on March 9, 2010, approved by shareholders at the Company's Annual General Meeting held on August 17, 2010 and extended for two years at the Company's Annual General and Special Meeting held on August 17, 2012.

AUDIT COMMITTEE INFORMATION

Charter

The Company's Audit Committee is governed by an Audit Committee Charter, the text of which is attached as Appendix C of this AIF.

Composition

The Company's Audit Committee consists of three directors: Bruce McIntyre (Chairman), Frank Borowicz and Gregg Vernon. As defined in Multilateral Instrument 52-110 - *Audit Committees* ("MI 52-110"), Bruce McIntyre, Frank Borowicz and Gregg Vernon are deemed "independent".

A member of the Audit Committee is "independent" if the member has no direct or indirect material relationship with the Company. A material relationship means a relationship which could, in the view of the Company's Board of Directors, reasonably interfere with the exercise of the member's independent judgment.

Relevant Education and Experience

MI 52-110 provides that a member of the Audit Committee is considered to be "financially literate" if he has the ability 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 complexities of the issues that can reasonably be expected to be raised by the Company.

All of the members of the Company's Audit Committee are considered to be "financially literate", as that term is defined in MI 52-110.

Bruce McIntyre, P.Geol., Chairman

Mr. McIntyre has over 32 years of oil and gas experience and a proven track record of finding quality oil and gas reserves. Mr. McIntyre is currently the Executive Director of New Zealand Energy Corp., a publicly-traded company which is focused on the production, development and exploration of oil and natural gas prospects in New Zealand. Previously, Mr. McIntyre was President and Chief Executive Officer of Sebring Energy Inc., a private Alberta-based exploration and production company that was sold in July 2007. He has also held various other management positions including President and co-founder of Sommer Energy Ltd., President of TriQuest Energy Corp., President and CEO of BXL Energy Ltd. and Exploration Manager for Gascan Resources. Mr. McIntyre is a member of the American Association of Petroleum Geologists, has a Professional Geologist designation with the Association of Professional Engineers and Geoscientists of Alberta and was the President of the Canadian Society of Petroleum Geologists in 2002.

Frank Borowicz, QC, CA (Hon)

Mr. Borowicz has over 35 years of experience in corporate governance and regulatory compliance. He is a retired partner of the international law firm Davis LLP and is a Governor of the Vancouver Board of Trade. He served as Chairman of the BC Industry Training Authority and is an independent director of several public and private companies. Educated at Harvard, Dalhousie and Loyola, Mr. Borowicz is a member of the Institute of Corporate Directors, is a Queens Counsel, and is an honourary member of the Institute of Chartered Accountants.

Gregg Vernon, P.Eng.

Mr. Vernon is a designated professional engineer with over 30 years of international oil and gas industry experience, including managing and administrating major projects in China, Eastern Canada and South America. He is currently the President of Bohica Oil & Gas. Previously, Mr. Vernon was the interim Chief Operating Officer of PetroMagdalena Energy Corp. (formerly Alange Energy Corp.), a Canadian-based international oil and gas exploration and production company until its sale in 2012. He is one of the founders of Petro Andina Resources Ltd., a Canadian company with operations in South America. Mr. Vernon's diverse technical experience provides a strong asset to the Hemisphere's Board of Directors. He is a University of Alberta graduate with his degree in Engineering and is a member of the Society of Petroleum Engineers.

External Auditors

The Company's external auditor is Smythe Ratcliffe LLP located at Suite 700, 355 Burrard Street, Vancouver, British Columbia V6C 2G8.

The fees paid by the Company to its external auditor in each of the last two fiscal years (including the ten month period ended December 31, 2012) are as follows:

Fiscal Year Ending	Audit Fees(1)	Audit Related Fees(2)	Tax Fees(3)	All Other Fees(4)
December 31, 2012	$38,000	Nil	$9,500	Nil
February 29, 2012	$43,000	$8,100	$3,500	Nil

Notes:

(1) *"Audit Fees" include fees necessary to perform the annual audit and quarterly reviews of the Company's financial statements. Audit Fees include fees for review of tax provisions and for accounting consultations on matters reflected in the financial statements. Audit Fees also include audit or other attest services required by legislation or regulation such as comfort letters, consents, reviews of securities filings and statutory audits.*

(2) *"Audit Related Fees" include services that are traditionally performed by the auditor. These audit related services include employee benefit audits, due diligence assistance, accounting consultations on proposed transactions, internal control reviews, consultations on conversion to International Financial Reporting Standards and audit or attest services not required by legislation or regulation.*

(3) *"Tax Fees" include fees for all tax services other than those included in "Audit Fees" and "Audit Related Fees". This category includes fees for tax compliance, tax planning and tax advice. Tax planning and tax advice include assistance with tax audits and appeals, tax advice related to mergers and acquisitions and requests for rulings or technical advice from tax authorities.*

(4) *"All Other Fees" include all other non-audit services.*

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR at www.sedar.com or Hemisphere's website at www.hemisphereenergy.ca. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans is contained in the Company's Information Circular for its most recent annual meeting of shareholders. Additional financial information is contained in the Company's audited annual financial statements and related Management's Discussion and Analysis for the ten months ended December 31, 2012.

Additional copies of this AIF, and any financial statements which have been issued by the Company, are available on the Company's website at www.hemisphereenergy.ca, upon request by mail at Suite 570, 789 West Pender Street, Vancouver, British Columbia V6C 1H2, by phone at (604) 685-9255, or by fax at (604) 685-9676.

APPENDIX A

FORM 51-101F2
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

To the Board of Directors of Hemisphere Energy Corporation (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, estimated using forecast prices and costs.

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 presented 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 as of December 31, 2012, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule	Evaluation of the P&NG Reserves of Hemisphere Energy Corporation, as of December 31, 2012, prepared January to February 2013	Canada	Nil	26,526	Nil	26,526

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

6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
March 19, 2013

Original signed by Vincent K. Hui, P.Eng.

Vincent K. Hui, P.Eng.
Petroleum Engineer and Associate

Original signed by Alec Kovaltchouk, P.Geo.

Alec Kovaltchouk, P.Geo.
Manager, Geoscience and Partner

Original signed by Cameron P. Six, P.Eng.

Cameron P. Six, P.Eng.
Vice-President, Engineering, Canada and Director

APPENDIX B

FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Hemisphere Energy Corporation (the "Company") is 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 December 31, 2012, estimated using forecast prices and costs.

An independent qualified reserves auditor has evaluated the Company's reserves data. The report of the independent qualified reserves auditor will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the Board of Directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves auditor;
(b) met with the independent qualified reserves auditor to determine whether any restrictions affected the ability of the independent qualified reserves auditor to report without reservation; and
(c) reviewed the reserves data with management and the independent qualified reserves auditor.

The Reserves Committee of the board of directors 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 Form 51-101F1 containing reserves data and other oil and gas information;
(b) the filing of Form 51-101F2, which is 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 judgements 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.

(signed) "*Don Simmons*"
Don Simmons
President & Chief Executive Officer

(signed) "*Dorlyn Evancic*"
Dorlyn Evancic
Chief Financial Officer

(signed) "*Greg Sadler*"
Greg Sadler
Director & Chairman of the Reserves Committee

(signed) *"Bruce McIntyre"*
Bruce McIntyre
Director & Member of the Reserves Committee

April 5, 2013

APPENDIX C

AUDIT COMMITTEE CHARTER

Purpose

The Audit Committee of Hemisphere Energy Corporation assists the Board of Directors in the oversight of its integrity in financial reporting as outlined in National Instrument 52-110 *Audit Committees* ("NI 52-110").

Composition

The Audit Committee consists of no less than three directors, each of whom is "financially literate" and "independent" as defined under NI 52-110, and is annually appointed by the Board of Directors. The Chair of the Audit Committee is appointed by the Board of Directors at the same time as the member appointment.

Mandate

- Assisting the Board of Directors in fulfilling their oversight responsibilities with respect to the review of financial statements and other relevant public disclosures, compliance with legal and regulatory requirements relating to financial reporting, the external auditors' qualifications and independence, and the performance of the internal audit function and the external auditors.
- Meeting quarterly to review and approve the quarterly financial statements and management's discussion and analysis for recommendation to the Board of Directors.
- Meeting annually to review and approve the audited annual financial statements and management's discussion and analysis for recommendation to the Board of Directors.
- Annually reviewing the performance of the external auditors.
- Nominating the external auditors for recommendation to the Hemisphere shareholders at the annual general meeting of the shareholders.
- Advising the Board of Directors on the remuneration of the external auditors based on the time required to complete the audit and preparation of the audited annual financial statements, and the difficulty of the audit and performance of the standard auditing procedures under generally accepted auditing standards and Generally Accepted Accounting Principles of Canada.

External Auditors

Hemisphere's external auditors are the independent representatives of the shareholders, yet are also accountable to the Board of Directors and the Audit Committee. The external auditors complete their audit procedures and reviews with professional independence, free from any undue interference from management or directors. The Audit Committee directs and ensures that the management fully co-operates with the external auditors in the course of carrying out their professional duties. The Audit Committee will have access to direct communications with the external auditors, if required.

The external auditors are prohibited from providing any non-audit services to Hemisphere, without the written consent of the Audit Committee unless such non-audit services are *De Minimus* Non-Audit Services as outlined in section 2.4 of NI 52-110. In determining whether the external auditors will be granted permission to provide non-audit services, the Audit Committee is to consider that the benefits to Hemisphere from the provision of such services, outweighs the risk of any compromise to or loss of the independence of the external auditors in carrying out their auditing mandate.

Notwithstanding the above non-audit services, the external auditors are prohibited at all times from carrying out any of the following services, while they are appointed the external auditors of Hemisphere:

(a) acting as an agent of Hemisphere for the sale of all or substantially all of the undertaking of Hemisphere; and

(b) performing any non-audit consulting work for any director or senior officer of Hemisphere in their personal capacity, but not as a director, officer or insider of any other entity not associated or related to Hemisphere.

The Audit Committee has the power to terminate the services of the external auditors, with or without the approval of the Board of Directors, acting reasonably.

Internal Controls

The Board of Directors will appoint a person who is responsible for implementing internal controls and performing the role as the internal auditor ensuring such controls are adequate and effective.

Continuous Disclosure Requirements

The Board of Directors will appoint a person who is responsible for ensuring that Hemisphere's continuous reporting requirements are met and in compliance with applicable regulatory requirements.

Annual Review

The Audit Committee annually reviews the Audit Committee Charter for adequacy and is then recommended to the Board of Directors for approval.