ANNUAL INFORMATION FORM

For the year ended December 31, 2013

April 14, 2014

TABLE OF CONTENTS

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
ºAPI	specific gravity of crude oil measured on the API gravity scale
AECO	Alberta Energy Company
M^3	Cubic metres
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 Energy Corporation's ("Hemisphere" or the "Company") 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 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 production in the Jenner and Atlee Buffalo areas of southeast Alberta and the Trutch area of 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 as a Tier 1 issuer under the symbol "HME".

History of the Company

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.

Fiscal year ended December 31, 2013

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

On April 24, 2013, the Company increased its credit facility from $5.5 million to $9.5 million (the "Credit Facility") as a result of reserve additions and production increases from its 2012 drilling activity.

On May 14, 2013, Hemisphere successfully graduated to Tier 1 on the TSX Venture Exchange. Tier 1 is the premier tier and is reserved for the most advanced issuers with the most significant financial resources on the TSX Venture Exchange.

On October 16, 2013, the Company entered into a formal letter of intent with an intermediate Canadian producer to purchase certain oil and gas assets in the Atlee Buffalo area of southeast Alberta. This acquisition included 100% working interest in 8.25 sections of contiguous land spanning two large Glauconitic oil pools at a cost of $3.35 million and an effective date of June 1, 2013. This acquisition subsequently closed on November 18, 2013 and was funded by the Credit Facility, which was increased to $10.5 million upon the closing.

On November 21, 2013, Hemisphere announced a Bought Deal Equity Financing (the “Financing”) with a syndicate of underwriters for aggregate gross proceeds of $4.3 million to accelerate its capital program focused on Jenner and the newly acquired Atlee Buffalo property. The Financing closed on December 10, 2013.

During the year, Hemisphere successfully drilled two horizontal oil wells in North Jenner. The Company also expanded its landholdings through Crown land sales acquiring 13.75 sections (8,800 acres) in southeast Alberta. Hemisphere upgraded its main oil battery by increasing its water handling capacity and debottlenecking its oil processing system as a means to optimize fluid rates at a number of existing wells and increase base oil production. Additionally, Hemisphere added a gas sweetening tower which removes H2S (hydrogen sulfide) from the gas stream allowing the Company to meet third party pipeline specifications and send solution gas to sales.

Recent Developments

On March 13, 2014, the Company announced that its Board of Directors approved the adoption of an Advance Notice Policy (the "Policy"), which took effect at such time of approval and is subject to shareholder ratification at the next annual general meeting of the Company. The purpose of the Policy is to: (i) facilitate an orderly and efficient annual general or, where the need arises, special meeting process, (ii) ensure that all shareholders receive adequate notice of the director nominations and sufficient information regarding all director nominees, and (iii) allow shareholders to register an informed vote after having been afforded reasonable time for appropriate deliberation.

From January to March 2014, Hemisphere successfully drilled and commenced production of three horizontal development wells (two at Jenner and one at Atlee Buffalo).

Significant Acquisitions

As result of a review by the British Columbia Securities Commission, an Amended and Restated Business Acquisition Report was filed on April 24, 2013 (the "Amended BAR"). The Amended Bar is in respect of the acquisition of certain oil producing assets in the Jenner area of southeast Alberta (the "Jenner Acquisition"). The Jenner Acquisition closed on January 27, 2012 and was effective as of January 1, 2012. The Amended BAR supersedes the Business Acquisition Report filed on June 25, 2012. The Amended BAR included, among other things, a summary of the reserves acquired in the Jenner Acquisition, an audited operating statement for the Jenner Acquisition and a pro forma operating statement of Hemisphere that gives effect to the Jenner Acquisition as required under National Instrument 51-102 - *Continuous Disclosure Requirements*.

Competition

The oil and gas industry is competitive in all its phases. The Company competes with numerous other participants 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 resource companies that have greater financial resources, staff and facilities than those of the Company. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. The Company believes that its competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development.

Seasonal Factors

The exploration for and development of oil and natural gas reserves is dependent on access to areas where production is to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances.

The Company's operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including, but not limited to, weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on the Company's financial condition and such effect could be material. See *"Risk Factors"*.

Environmental Regulation

The oil and gas industry is subject to environmental regulations pursuant to applicable legislation. Such legislation provides for restrictions and prohibitions on release or emission of various substances produced in association with certain oil and gas industry operations, and requires that well and facility sites be abandoned and reclaimed to the satisfaction of environmental authorities**.** No assurance can be given that the application of environmental laws to the business and operations of the Company will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Company's financial condition, results of operations or prospects. See *"Risk Factors"*.

Human Resources

As at December 31, 2013, Hemisphere had six full-time head office employees and one full-time field employee. Additionally, the Company had one full-time consultant, five part-time consultants and one full-time field contractor.

Specialized Skill and Knowledge

The Company relies on specialized skills and knowledge to gather, interpret and process geophysical data, operate production facilities and numerous additional activities required to produce oil and natural gas. The Company has employed a strategy of contracting consultants and other service providers to supplement the skills and knowledge of its permanent staff in order to provide the specialized skills and knowledge to undertake its oil and natural gas operation effectively.

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 they 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

The market events and conditions witnessed over the past several years, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to and reductions in commodity prices. The continued uncertainty in the global economic situation means that the Company, along with all other oil and gas entities, may continue to face restricted access to capital and increased borrowing costs. To the extent that external sources of capital become limited or unavailable or available on unfavourable terms, our ability to make capital investments and maintain existing properties may be constrained, and, as a result, Company's business, financial condition, results of operations and cash flow may be materially adversely affected.

Oil and natural gas prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, the actions of the other oil and natural gas producing countries and the ongoing global credit and liquidity concerns.

Volatility of Market Price of Common Shares

The market price of common shares may fluctuate due to a variety of factors relative to Hemisphere's business, including announcements of new developments, fluctuations in Hemisphere's operating results, sales of the common shares in the marketplace, failure to meet analysts' expectations, any public announcements made in regards to the Company, the impact of various tax laws or rates and general market conditions or the worldwide economy. In recent years, stock markets have experience significant price fluctuations, which have been unrelated to the operating performance of the affected companies. There can be no assurance that the market price of the common shares of the Company will not experience significant fluctuations in the future, including fluctuations that are unrelated to the Company's performance.

The volatility may affect the ability of holders to sell the common shares of the Company at an advantageous price.

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 exploration 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 natural 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' respective 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 natural 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 that 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 notice of articles nor articles 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 and natural gas. 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 a terrorist attack, it may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company does not have insurance to protect against the risk from terrorism.

Dilution

The Company may issue additional common shares in the future, which may dilute a shareholders’ holding in the Company. The Company’s articles permit the issuance of an unlimited number of common shares and shareholders will have no pre-emptive rights in connection with such further issuances. The Board of Directors of the Company have the discretion to determine the price and the terms of issue of further issuances of common shares. Also, additional common shares will be issued by the Company on the exercise of stock options under the Company’s stock option plan.

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 a licence or lease fails to meet the specific requirement of such licence or lease, such 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 natural 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 oil 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 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 believes it is 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.

Litigation Risks

In the normal course of the Company's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to personal injuries, property damage, property taxes, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company and as a result, could have a material adverse effect on Company's assets, liabilities, business, financial condition and results of operations. Even if the Company prevails in any such legal proceeding, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from the Company's business operations, which could adversely affect its financial condition.

Conflicts of Interest

There are potential conflicts of interest to which some of the directors and officers of the Company will be subject in connection with the operations of the Company. Some of the directors and officers are engaged and will continue to be engaged in the search of oil and gas interests on their own behalf and on behalf of other corporations, and situations may arise where the directors and officers will be in direct competition with the Company.

Conflicts of interest, if any, that arise will be subject to and be governed by procedures prescribed by the *Business Corporations Act* (British Columbia) (the "BCBCA") which requires a director or officer of a corporation who is a party to or is a director or an officer of or has a material interest in any person who is a party to a material contract or proposed material contract with the Company, to disclose his interest and to refrain from voting on any matter in respect of such contract unless otherwise permitted under the BCBCA.

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. Payments 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 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 government of Canada and the Provincial Governments, 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, as are numerous projects to increase rail handling and transportation of oil and other liquid hydrocarbons.

The North American Free Trade Agreement

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, United States, 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 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes, to minimize disruption of contractual arrangements and to 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 each Province respectively. 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.

Under the current “Alberta Royalty Framework” ("ARF"), royalty rates for oil and natural gas are set by a single sliding rate formula which is applied monthly using separate variables to account for production rates and market prices. The maximum royalty payable under the ARF for oil is 40%, and the maximum royalty payable for natural gas is 36%. The Alberta government also levies royalties on volumes of propane, butane, pentanes plus, bitumen and sulphur produced from Crown lands. A five year program of transitional royalty rates with the intent of promoting new drilling ended effective December 31, 2013, and as of January 1, 2014, all producers operating under transitional royalty rates became subject to the ARF rates described above.

There are several incentive programs currently in effect to stimulate oil and gas investment in Alberta. The Natural Gas Deep Drilling Program provides royalty incentives for deep natural gas wells. A new-well incentive program applies to wells beginning production of conventional oil and natural gas and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels or 500 MMcf of natural gas. Similar 5% royalty rates are applicable to horizontal gas wells, coal bed methane wells and shale gas wells. 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”). 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 a freehold mineral tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands. The freehold mineral tax is levied on an annual basis on calendar year production using a formula that takes into consideration, among other things, the volume of monthly production, a specified rate of tax for both oil and gas and the percentages that the owners hold in the title.

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 British Columbia 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 British Columbia 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.

The Government of British Columbia has several royalty credit and royalty reduction programs intended to increase the competitiveness of low productivity natural gas wells, including the Deep Royalty Credit, the Deep Re-Entry Royalty Credit Program, the Deep Discovery Royalty Credit Program, the Coalbed Gas Royalty Reduction and Credit Program, the Marginal Royalty Reduction Program, the Ultra-Marginal Royalty Reduction Program, and the Net Profit Royalty Reduction Program.

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 occurs first.

The Government of British Columbia also maintains an 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.

The Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation has been amended effective April 1, 2013 to provide for a 3% minimum royalty on affected wells with deep well/deep re-entry credits. The 3% minimum royalty applies to deep wells when the net royalty payable would otherwise be zero for a production month.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes to the Provincial Government. 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.

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 Governments of Alberta and British Columbia has implemented legislation providing for the reversion to the Crown of mineral rights of 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, for leases and licenses issued subsequent to January 1, 2009, shallow rights reversion is applied at the conclusion of the primary term of the lease or license. Although Alberta Energy had previously announced that shallow rights reversions would be implemented for leases and licences that had been granted prior to January 1, 2009 by the service of reversion notices at the end of their primary terms, in April 2013, it communicated to industry that it was deferring the service of such notices indefinitely.

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 is consolidated in the *Environmental Protection and Enhancement Act* (Alberta) (the "EPEA") 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.

The Province of Alberta has created a single regulator for upstream oil and gas, oil sands and coal development activity, the Alberta Energy Regulator (the "AER") assuming the functions of multiple regulatory bodies. The objective is enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners. On June 17, 2013, the AER assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the Oil and Gas Conservation Act ("ABOGCA"). On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development ("AESRD") in respect of the disposition and management of public lands under the Public

Lands Act. On March 29, 2014, the AER is expected to assume the energy related functions and responsibilities of AESRD in the areas of environment and water under the Environmental Protection and Enhancement Act and the Water Act, respectively. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The restructuring of the agencies implementing regulation has not been accompanied by substantive amendments to the underlying Provincial Government policy or legislation.

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 Government of Alberta. 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 to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA 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.

The first regional plan under the ALSA, the Lower Athabasca Regional Plan (the "LARP"), came into effect on September 1, 2012. The LARP covers the northeast corner of Alberta and the entirety of the Athabasca oil sands region. The next regional plan to take effect is the South Saskatchewan Regional Plan (the "SSRP") which covers approximately 83,764 square kilometres and includes 45% of the provincial population. The SSRP was released in draft form in 2013. All input was gathered as of February 28, 2014, and the Government has advised that summary results will be made publically available soon. With the implementation of the new Alberta regulatory structure under the AER, AESRD will remain responsible for development and implementation of regional plans. However, the AER will take on some responsibility for implementing regional plans in respect of energy related activities.

The Government of 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 2013, 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 British Columbia, the Oil and Gas Activities Act (the "OGAA") governs conventional oil and gas producers, shale gas producers and other operators of oil and gas facilities. Under the OGAA, the British Columbia Oil and Gas Commission (the "Commission") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for oil and gas activities. The Environmental Protection and Management Regulation establishes the Government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The Commission is required to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. In addition, the Petroleum and Natural Gas Act requires proponents to obtain various approvals before undertaking exploration or production work. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

In February, 2008, the Government of 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. As at year-end 2013, Hemisphere did not have an interest in any facilities in British Columbia that emit more than 25,000 tonnes of carbon dioxide equivalent per year.

Federal

Pursuant to the Jobs, Growth and Long-term Prosperity Act which received Royal Assent on June 29, 2012, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime that came in to force on July 6, 2012. The changes to the environmental legislation under the Prosperity Act are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

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, the Government of 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 CO_2 equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 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 CO_2 equivalent per year per facility.

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund (as defined in the Updated Action Plan) 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 is to increase over time rising from $20 per tonne in 2013 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 are to 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 are to be verified before offset credits can 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 is to 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 is to 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.

Although draft regulations for the implementation of the Updated Action Plan were intended to become binding on January 1, 2010, only regulations pertaining to carbon dioxide emissions from coal-fired generation of electricity have been enacted 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, McDaniel & Associates Consultants Ltd. ("McDaniel") prepared a report for the Company dated March 7, 2014 with the effective date December 31, 2013 (the "McDaniel Report"). The McDaniel 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 McDaniel Report based on forecast price and certain cost assumptions. The tables summarize the data contained in the McDaniel 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 McDaniel. It should not be assumed that the undiscounted or discounted net present values of future net revenue attributable to reserves estimated by McDaniel 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 McDaniel Report is based on certain factual data supplied by the Company and McDaniel'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 McDaniel. McDaniel 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

	Heavy Oil		**Natural Gas**		**Natural Gas Liquids**	
	Gross(1) (Mbbl)	Net(2) (Mbbl)	Gross(1) (MMcf)	Net(2) (MMcf)	Gross(1) (Mbbl)	Net(2) (Mbbl)
Proved						
Developed Producing	520.1	437.6	640.2	579.1	3.9	2.8
Developed Non-Producing	22.7	20.6	3.0	2.3	-	-
Undeveloped	592.6	508.7	157.8	143.3	-	-
Total Proved	**1,135.4**	**966.9**	**801.0**	**724.7**	**3.9**	**2.8**
Probable	696.4	576.5	597.2	507.0	4.9	3.4
Total Proved Plus Probable	**1,831.9**	**1,543.5**	**1,398.1**	**1,231.6**	**8.8**	**6.3**

Notes:

(1) Gross reserves are working interest reserves before royalty deductions.

(2) Net reserves include working interest reserves after royalty deductions plus royalty interests.

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

(M$)	**Before** Income Taxes and Discounted at[1] 0%	5%	10%	15%	20%
Proved					
Developed Producing	17.3	15.4	13.9	12.7	11.7
Developed Non-Producing	0.2	0.3	0.3	0.3	0.3
Undeveloped	15.4	12.6	10.4	8.7	7.3
Total Proved	**32.9**	**28.3**	**24.6**	**21.7**	**19.2**
Probable	23.2	17.5	13.5	10.8	8.8
Total Proved Plus Probable	**56.1**	**45.8**	**38.2**	**32.4**	**28.0**

Note:

(1) Costs associated with extraction of natural gas products have in most cases been deducted from the natural gas revenues.

(M$)	**After** Income Taxes and Discounted at 0%	5%	10%	15%	20%
Proved					
Developed Producing	17.3	15.4	13.9	12.7	11.7
Developed Non-Producing	0.2	0.3	0.3	0.3	0.3
Undeveloped	13.5	11.1	9.1	7.6	6.4
Total Proved	**31.0**	**26.8**	**23.3**	**20.5**	**18.3**
Probable	17.9	13.2	10.1	7.9	6.4
Total Proved Plus Probable	**48.9**	**40.0**	**33.4**	**28.5**	**24.6**

($/boe)	Unit Value **Before** Income Taxes Discounted at 10%/year
Proved	
Developed Producing	22.05
Developed Non-Producing	11.47
Undeveloped	16.88
Total Proved	**19.35**
Probable	16.91
Total Proved Plus Probable	**18.41**

Total Future Net Revenue Undiscounted – Forecast Prices and Costs

(M$)	Sales Revenue[1]	Royalties[2]	Operating Costs	Development Costs	Well Abandon-ment / Other Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Proved	91,312	13,246	33,034	10,652	1,506	32,874	1,867	31,008
Proved Plus Probable	151,460	23,325	54,347	15,778	1,891	56,120	7,238	48,883

Notes:

(1) Sales Revenue includes all non-producing income.

(2) Royalties includes any net profits interests paid.

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$)	Unit Value Before Income Taxes Discounted at 10%/Year ($/bbl; $/mcf)
Proved		
Light and Medium Crude Oil (including solution gas and associated by-products)	-	-
Heavy Oil (including solution gas and associated by-products)	24,520	25.36
Natural Gas (including associated by-products)	105	0.48
Proved Plus Probable		
Light and Medium Crude Oil (including solution gas and associated by-products)	-	-
Heavy Oil (including solution gas and associated by-products)	37,949	24.59
Natural Gas (including associated by-products)	218	0.42

Note:
Unit Values are based on net reserve volumes.

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

McDaniel employed the following pricing, exchange rate and inflation rate assumptions in estimating the Company's reserves data using forecast prices and costs as of January 1, 2014.

	Oil			**Natural Gas**	**NGL**				
Year	WTI Crude Oil ($US/bbl)	Edmonton Light Crude Oil ($Cdn/bbl)	WCS Crude Oil ($Cdn/bbl)	Alberta AECO Spot Price ($Cdn/MMBtu)	Edmonton Condensate and Natural Gasolines ($Cdn/bbl)	Edmonton Butanes ($Cdn/bbl)	Edmonton Propane ($Cdn/bbl)	Inflation Rate (%/Year)	Exchange Rate ($US/$Cdn)
2014	95.00	105.00	76.50	4.00	102.50	76.60	50.20	2.0	0.95
2015	95.00	102.50	79.60	4.25	101.60	77.80	50.50	2.0	0.95
2016	95.00	100.20	80.40	4.55	100.60	78.60	50.60	2.0	0.95
2017	95.00	97.70	80.90	4.75	101.20	79.00	51.30	2.0	0.95
2018	95.30	98.00	81.10	5.00	101.50	79.20	52.00	2.0	0.95
2019	96.60	99.40	82.20	5.25	102.90	80.30	53.20	2.0	0.95
2020	98.50	101.30	83.80	5.35	105.00	81.90	54.10	2.0	0.95
2021	100.50	103.40	85.50	5.45	107.00	83.50	55.20	2.0	0.95
2022	102.50	105.40	87.20	5.55	109.20	85.20	56.30	2.0	0.95
2023	104.60	107.60	89.00	5.65	111.50	87.00	57.40	2.0	0.95
2024	106.70	109.70	90.80	5.75	113.70	88.60	58.50	2.0	0.95
Thereafter	Escalation Rate of 2%								

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 year ended December 31, 2013 were $70.75/bbl for oil, $68.60/bbl for NGLs and $3.45/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, 2013, derived from the McDaniel Report using forecast prices and cost estimates, reconciled to the Company's gross reserves as at December 31, 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)
Dec. 31, 2012	**737.4**	**392.8**	**1,130.2**	**406.0**	**318.0**	**724.0**	**7.2**	**7.0**	**14.2**	**812.4**	**452.6**	**1,265.0**
Extensions	208.1	204.2	412.3	135.2	34.4	169.6	0.0	0.0	0.0	230.6	209.9	440.6
Infill Drilling	-	-	-	-	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	82.6	(64.0)	18.6	123.2	94.6	217.8	(2.2)	(2.1)	(4.3)	100.9	(50.3)	50.6
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	246.4	163.8	410.2	309.7	150.2	459.9	-	-	-	298.0	188.8	486.9
Dispositions	-	(0.3)	(0.3)	-	-	-	-	-	-	-	(0.3)	(0.3)
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	139.1	-	139.1	173.1	-	173.1	1.1	-	1.1	169.1	-	169.1
Dec. 31, 2013	**1,135.4**	**696.5**	**1,831.9**	**801.0**	**597.2**	**1,398.2**	**3.9**	**4.9**	**8.8**	**1,272.8**	**800.9**	**2,073.7**

Undeveloped Reserves

Undeveloped reserves were attributed in accordance with the standards and procedures in the Canadian Oil and Gas Evaluation Handbook.

The following table sets out the Company's gross reserves, first attributed by year.

	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, 2011	-	-	-	-	-	-	-	-
February 29, 2012	-	-	90.0	90.0	-	-	-	-
December 31, 2012(1)	-	-	157.4	243.0	-	-	-	-
December 31, 2013	-	-	334.1	592.6	157.8	157.8	-	-
Probable Undeveloped								
February 28, 2011	-	-	75.0	75.0	1	24	-	-
February 29, 2012	-	-	175.0	175.0	3	27	-	-
December 31, 2012(1)	-	-	69.9	190.3	-	-	-	-
December 31, 2013	-	-	327.3	504.3	117.4	117.4	-	-

Note:

(1) Year-end reporting date changed from February 28 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 natural 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 McDaniel, an independent engineering firm.

As circumstances change and additional data becomes 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$)	Proved Plus Probable Reserves (M$)
2014	7,067.8	7,175.9
2015	3,584.2	8,601.8
2016	-	-
2017	-	-
2018	-	-
Remaining Years	-	-
Total Undiscounted	**10,652.0**	**15,777.7**

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 natural 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 reserve 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" 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

Description of Oil and Gas Properties

Hemisphere's oil and gas properties at December 31, 2013 are located in Alberta and British Columbia. The following map identified the location of the Company's assets:

Core Assets

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 18,819 net acres (7,616 ha). The property, 95% operated by Hemisphere, has multiple zones of potential, existing infrastructure, and low cost drilling and completions. The Company drilled two horizontal oil wells during the year ended December 31, 2013.

Atlee Buffalo, Southeast Alberta

The Atlee Buffalo property is accessible year-round and is located approximately 30 km east of Jenner, Alberta. Hemisphere has a 100% working interest in approximately 5,253 net acres (2,126 ha). The property has high original oil in place in two large Glauconitic pools and very low current recovery factors. Primary recovery at this location will be through horizontal drilling and Secondary recovery through water and/or polymer flood.

Non-Core Assets

Trutch (Tommy Lakes), 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 23,102 net acres (9,349 ha). Competitors to the east and south of the Trutch property 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 2013.

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 25% in nine producing Edmonton Sands natural gas wells on the property. The Company did not drill any wells in this area during 2013.

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 2013.

Heathdale, Southeast Alberta

The Heathdale property is located northeast of Brooks, Alberta and north of Hemisphere's Jenner Property. The Company has 3.0 sections (1,920 acres) of land in this area. The Company did not drill any wells in this area during 2013.

Oil and Gas Wells

The following table summarizes Hemisphere's interest as at December 31, 2013 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
Atlee Buffalo, Alberta	2.0	2.0	2.0	2.0	20.0	20.0	-	-
Jenner, Alberta	18.0	17.8	-	-	17.0	17.0	-	-
Sylvan Lake, Alberta	-	-	9.0	1.45	3.0	1.5	1.0	1.0
Wainwright, Alberta	-	-	-	-	-	-	1.0	0.6875
Trutch, British Columbia	-	-	4.0	1.4	-	-	2.0	1.5
Total	**20.0**	**19.8**	**15.0**	**4.85**	**40.0**	**38.5**	**4.0**	**3.1875**

Exploration and Drilling Activity

The following table summarizes the gross and net exploration and development wells in which Hemisphere participated during the year ended December 31, 2013:

	Exploratory Wells		**Development Wells**	
	Gross	Net	Gross	Net
Oil	-	-	2.0	2.0
Gas	-	-	-	-
Service Wells	-	-	-	-
Stratigraphic Test Wells	-	-	-	-
Dry Wells	-	-	-	-
Total	**-**	**-**	**2.0**	**2.0**

Production History

	Three Months Ended			
	March 31, 2013 Q1	June 30, 2013 Q2	Sept. 30, 2013 Q3	Dec. 31, 2013 Q4
Average daily production				
Oil (bbl/d)	371	335	375	443
Natural gas (Mcf/d)	232	412	501	746
NGL (bbl/d)	4	3	3	2
Combined (boe/d)	414	407	461	569
Average sales prices				
Oil ($/bbl)	59.12	72.99	87.76	65.70
Natural gas ($/Mcf)	3.42	3.55	2.57	3.99
NGL ($/bbl)	74.43	62.55	69.65	64.21
Combined ($/boe)	55.66	64.18	74.56	56.55
Operating netback ($/boe)				
Petroleum and natural gas revenue	55.66	64.18	74.56	56.55
Royalties	7.92	10.87	15.02	10.78
Operating costs	14.96	15.62	10.47	18.72
Transportation costs	2.84	3.26	2.66	3.23
Operating netback	29.95	34.44	46.42	23.83

Production Estimates

The following table discloses, by product type, the total volume of production estimated by McDaniel for the year ending December 31, 2014 in the estimates of 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				
Atlee Buffalo	136.4	177.8	-	166.0
Heathdale	-	-	-	-
Jenner	469.6	236.7	-	509.1
Sylvan Lake	-	33.7	-	5.6
Wainwright	-	-	-	-
British Columbia				
Trutch	-	94.8	2.5	18.3
Total	**606.0**	**543.0**	**2.5**	**699.0**

Proved Plus Probable	**Heavy Oil** (bbl/d)	**Gas** (Mcf/d)	**NGL** (bbl/d)	**Total** (boe/d)
Alberta				
Atlee Buffalo	137.0	179.2	-	166.9
Heathdale	-	-	-	-
Jenner	493.7	252.9	-	535.9
Sylvan Lake	-	34.0	-	5.7
Wainwright	-	40.8	-	6.8
British Columbia				
Trutch	-	95.9	2.5	18.5
Total	**630.7**	**602.9**	**2.5**	**733.8**

Developed and Undeveloped Lands

The following table summarizes, by province, Hemisphere's developed and undeveloped landholdings as at December 31, 2013:

	Developed Acres		**Undeveloped Acres**		**Total Acres**	
	Gross	Net	Gross	Net	**Gross**	**Net**
Alberta						
Atlee Buffalo	1,920	1,920	3,360	3,333	**5,280**	**5,253**
Buffalo Lake	-	-	1,280	1,280	**1,280**	**1,280**
Heathdale	-	-	1,920	1,920	**1,920**	**1,920**
Jenner	7,528	6,330	13,560	12,489	**21,088**	**18,819**
Sylvan Lake	1,920	288	-	-	**1,920**	**288**
British Columbia						
Trutch	18,755	5,883	18,115	17,219	**36,870**	**23,102**
Total	**30,123**	**14,421**	**38,235**	**36,241**	**68,358**	**50,662**

Hemisphere has 4,600 gross (4,536 net) acres in southeastern Alberta scheduled to expire in 2014.

Forward Contracts

As at December 31, 2013, 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 $32,217 in reclamation costs during 2013. Hemisphere estimates well abandonment costs by area. Such costs are included in the McDaniel Report as deductions in arriving at future net revenue. The Company expects to incur such costs for 36.1 net wells under the proved category and 44.1 net wells under the proved plus probable category. The expected total abandonment costs included in the McDaniel Report (forecast pricing) under the total proved reserves category is $1,506,200 undiscounted ($379,600 discounted at 10%), of which no costs are estimated to be incurred during the next three years.

	Total Proved M$	**Total Proved Plus Probable M$**
2014	-	-
2015	-	-
2016	-	-
2017	-	-
2018	-	-
Remainder	1,506.2	1,890.5
Total for all years undiscounted	1,506.2	1,890.5
Total for all years discounted at 10% per year	**379.6**	**385.0**

As at December 31, 2013, the Company had $156,977 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 $105,535 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, 2013, and has continued to build its tax pools to over $30 million with additional capital expenditures and acquisitions. Based on corporate projections, Hemisphere's net income for 2014 will be offset by the tax pools and no tax is expected to be incurred for 2014. The Company estimates that it will not be required to pay income taxes until 2015.

Costs Incurred

The following table summarizes Hemisphere's property acquisition costs, exploration costs and development costs for the year ended December 31, 2013:

	Property Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
Total	**3,092,055**	**-**	**485,389**	**6,391,729**

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 hereof, there are 61,344,997 common shares issued and 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 hereof, the Company had 5,675,000 stock options outstanding.

Warrants

As of the date hereof, the Company had a total of 2,053,775 warrants outstanding priced at $0.75 each with a December 9, 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
2013			
January	0.61	0.51	21,400
February	0.56	0.40	52,800
March	0.52	0.44	32,200
April	0.52	0.40	50,300
May	0.50	0.40	29,600
June	0.55	0.42	37,800
July	0.55	0.42	33,600
August	0.63	0.50	33,600
September	0.68	0.56	37,700
October	0.69	0.56	68,900
November	0.64	0.50	41,500
December	0.55	0.45	40,000
2014			
January	0.69	0.49	126,800
February	0.85	0.65	135,500
March	0.81	0.67	71,600
April 1 to 14	0.74	0.68	56,700

PRIOR SALES

The following table sets forth, for each class of securities of the Company that is outstanding but not listed or quoted on a marketplace, the price at which securities of the class have been issued during the fiscal year ended December 31, 2013 and the number of securities of the class issued at that price and the date on which the securities were issued.

Date of issue	Securities	Price per Security	Number of Securities
January 25, 2013	Warrants	$0.90[(1)]	44,150
March 8, 2013	Stock Options	$0.50[(2)]	250,000
December 9, 2013	Warrants	$0.75[(3)]	2,091,275

Notes:

(1) On January 25, 2013, the Company closed the second and final tranche of a private placement consisting of 86,900 units at a price of $0.65 per unit for gross proceeds of $56,485. Each unit consisted of one Common Share and one-half of one non-transferrable common share purchase warrant. Each whole warrant entitled the holder to purchase one additional common share at a price of $0.90 until January 25, 2014. In conjunction with the closing of the private placement, 700 finders' warrants were issued. Each finders' warrant entitled the holder to purchase one Common Share at a price of $0.90 until January 25, 2014.

(2) Represents the exercise price of stock options.

(3) On December 9, 2013, the Company closed the bought deal equity financing consisting of 4,182,550 units, comprised of one common share and one half of one warrant of Hemisphere (together, the "Units") at a price of $0.55 per Unit and 3,077,000 common shares to be issued on a "CEE flow-through" basis (the "CEE Flow-Through Shares") at a price of $0.65 per CEE Flow-Through Share for aggregate gross proceeds of $4,300,453. Each whole warrant will entitle the holder to acquire one common share of the Company at a price of $0.75 per common share expiring 12 months after the closing of the Offering.

On December 16, 2013, the Company's Board of Directors approved 685,000 stock options be granted to employees, consultants and directors of the Company; however, these stock options were not granted until January 6, 2014 at $0.55 each with a January 6, 2019 expiry.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the knowledge of the directors and executive officers of Hemisphere, none of the securities of Hemisphere are held in escrow or are subject to a contractual restriction on transfer as at the date hereof.

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, Canada	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, Encana Corporation and Alberta Energy Company.
Charles O'Sullivan, B.Sc.(2)(3) Vancouver, British Columbia, Canada	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, Canada	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, Canada	Director	July 2008	Most recently Executive Director of New Zealand Energy Corp. and now solely serves on their Board of Directors. 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, Canada	Director	July 2008	Senior Staff Reservoir Engineer with Cenovus Energy Inc. and predecessor companies since 1995.
Gregg Vernon, P. Eng.(1)(4) Bogota, Cundinamarca, Colombia	Director	August 2006	Currently Interim President and Chief Executive Officer of Petrodorado Energy Ltd. since October 2013. Currently 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, Vice President Business Development of Petro Andina Resources Ltd.
Andrew Arthur, P. Geol. Delta, British Columbia, Canada	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, Canada	Vice President, Engineering	May 2011	Previously an Engineer at Hemisphere since January 2011. Prior thereto was an Engineer at Solaris MCI and Talisman Energy Inc.
Dorlyn Evancic, CGA Port Coquitlam, British Columbia, Canada	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.

As at the date hereof, the directors and officers of the Company, as a group, owned directly or indirectly 3,708,726 common shares or approximately 6% (14% on a fully diluted basis) of the issued and outstanding common shares.

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 hereof, 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 order 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 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, 2013, 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 McDaniel, the Company's independent engineering evaluator, and Smythe Ratcliffe LLP, the Company's independent auditors.

Smythe Ratcliffe LLP 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 McDaniel 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 33 years of oil and gas experience and a proven track record of finding quality oil and gas reserves. Mr. McIntyre was most recently the Executive Director of New Zealand Energy Corp. and now solely serves on their Board of Directors. 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 Ltd. 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 35 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 interim President and Chief Executive Officer of Petrodorado Energy Ltd. and President of Bochica Oil & Gas Inc. (private company). 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. 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 are as follows:

Fiscal Year Ending	Audit Fees(1)	Audit Related Fees(2)	Tax Fees(3)	All Other Fees(4)
December 31, 2013	40,000	27,000	9,500	Nil
December 31, 2012(5)	38,000	2,000	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.*

(5) *Represents the ten months ended December 31, 2012.*

EXEMPTION

The Company is relying upon the exemption in Section 6.1 of MI 52-110 as TSX Venture Issuer.

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 year ended December 31, 2013.

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 email at info@hemisphereenergy.ca, 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

March 7, 2014

Hemisphere Energy Corporation
570, 789 West Pender St.
Vancouver, British Columbia
V6C 1H2

Attention: The Board of Directors of Hemisphere Energy Corporation

Re: **Form 51-101F2**
Report on Reserves Data by an Independent Qualified Reserves Evaluator
of Hemisphere Energy Corporation (the "Company")

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

1. We have evaluated the Company's reserves data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, 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, for the year ended December 31, 2013, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate) Audited	Evaluated	Reviewed	Total
March 7, 2014	Canada	-	38,168	-	38,168

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:

MCDANIEL & ASSOCIATED CONSULTANTS LTD.

(Signed) *"P.A. Welch"*
P.A. Welch, P. Eng.
President & Managing Director

Calgary, Alberta
March 7, 2014

APPENDIX "B"

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

Management of Hemisphere Energy Corporation (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as December 31, 2013, 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.

(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 14, 2014

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.